# Baytex

DELIVERING SUSTAINABLE SUCCESS

BAYTEX ENERGY TRUST 2006 ANNUAL REPORT

## CORPORATE PROFILE

Baytex Energy Trust possesses the attributes required to deliver sustainable success year after year. Quality heavy oil, light crude and natural gas assets are focused in three western Canadian provinces and managed through prudent financial and operational strategies from Baytex's head office in Calgary, Alberta. Baytex trust units are listed on the TSX (BTE.UN) and on the NYSE (BTE) and we have a proven track record of delivering industry-leading total returns to our unitholders.

*Year ended December 31*
*($ thousands, except per unit amounts)*

| | | 2006 | 2005 | % CHANGE |
|---|---|---|---|---|
| FINANCIAL | Petroleum and natural gas sales | 556,689 | 546,940 | 2 |
| | Cash flow from operations *(1)* | 274,662 | 227,465 | 21 |
| | Per unit – basic | 3.77 | 3.38 | 12 |
| | – diluted | 3.45 | 3.12 | 11 |
| | Cash distributions | 143,072 | 114,221 | 25 |
| | Per unit | 2.16 | 1.80 | 20 |
| | Net income | 147,069 | 79,876 | 84 |
| | Per unit – basic | 2.02 | 1.19 | 70 |
| | – diluted | 1.91 | 1.15 | 66 |
| | Capital expenditures | 133,083 | 152,449 | (13) |
| | Total debt | 364,417 | 418,476 | (13) |
| | Trust units outstanding at December 31 *(thousands)* *(2)* | 77,498 | 71,475 | 8 |
| OPERATING | Production | | | |
| | Light oil and NGL *(bbl/d)* | 3,735 | 3,842 | (3) |
| | Heavy oil *(bbl/d)* | 21,325 | 21,265 | – |
| | Total oil *(bbl/d)* | 25,060 | 25,107 | – |
| | Natural gas *(MMcf/d)* | 55.4 | 60.4 | (9) |
| | Oil equivalent *(boe/d)* *(3)* | 34,292 | 35,177 | (3) |
| | Reserves, proved plus probable *(4)* | | | |
| | Oil and NGL *(Mbbl)* | 120,443 | 110,255 | 9 |
| | Natural gas *(Bcf)* | 148.1 | 176.4 | (16) |
| | Oil equivalent *(Mboe)* | 145,120 | 139,657 | 4 |
| | Reserve life index *(years, proved plus probable)* | 11.6 | 11.0 | 5 |

*(1) Cash flow from operations and cash flow from operations per unit are non-GAAP terms that represent cash generated from operating activities before changes in non-cash working capital and other operating items. The Trust's cash flow from operations may not be comparable to other companies. The Trust considers cash flow a key measure of performance as it demonstrates the Trust's ability to generate the cash flow necessary to fund future distributions and capital investments.*

*(2) Number of trust units outstanding includes the conversion of exchangeable shares at the respective exchange ratios in effect at the end of the reporting periods.*

*(3) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf :1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

*(4) Reserves information as at December 31, 2006 and 2005 is prepared in accordance with NI 51-101.*

We delivered best-in-class performance on both operational and financial fronts and, consequently, were rewarded with BEST-IN-CLASS performance in returns to our investors. Our returns rank us as the best performer among all oil and gas income trusts for each of the one-year, two-year and three-year periods ended on December 31, 2006.

RAYMOND T. CHAN *President & CEO*

## MESSAGE TO UNITHOLDERS

2006 was indeed a banner year for Baytex Energy Trust. We delivered best-in-class performance on both the operational and financial fronts and, consequently, were rewarded with best-in-class performance in returns to our investors.

### *Operational Accomplishments*

Baytex subscribes to a self-sustaining business model whereby operational focus is principally on internal property development, augmented by acquisitions for enhancement of asset base for long-term benefits. During 2006, capital investments totaled $133 million with essentially all amounts spent on exploration and development activities. The results of this program are spectacular. While the spending level was modest at 48 percent of cash flow, the program maintained production at the same level as last year and generated enough reserves to replace 145 percent of production during the year. Finding and development costs for the year were $7.31 per proved plus probable boe, yielding a capital investment recycle ratio of 3.7 times. Our reserve life index continues to improve and stood at 11.6 years at the end of 2006. Reserves per trust unit were held constant at 1.8 boe despite a three percent increase in the diluted number of trust units outstanding. Our three-year capital performance (covering the period since inception of the Trust) is equally strong, with average finding and development costs of $7.36 per boe and a recycle ratio of 3.3 times. These capital efficiency measures are some of the best posted by the oil and gas income trust sector for 2006 and for the three-year period.

Capital efficiency was led by our activities at Celtic, a heavy oil property we purchased in the fourth quarter of 2005. Through recompletions of existing well bores and the drilling of 20 wells, production in this area increased from 2,500 boe/d at year-end 2005 to over 4,500 boe/d at year-end 2006. We have also identified numerous similar opportunities that will ensure that Celtic remains one of our most active areas for capital investment in the near future.

Significant gains were also experienced at Seal, our large resource heavy oil property in the Peace River oil sands region in Alberta. We added two horizontal production wells during the year, bringing the total producing well count to eight, and drilled three vertical stratigraphic test wells to sample oil and reservoir quality in various blocks of our land holdings. The results of our work, plus those of the other operators in the Seal area allowed our independent evaluators to increase the reserves recognized at year-end 2006 to 13 million boe from four million boe one year ago. We have plans to drill 18 new horizontal production wells and a minimum of four stratigraphic wells in 2007. We also plan to commence field tests in 2007 of enhanced recovery through thermal operations, which, if successful, will lead to substantial increases in production and reserves recovery rates. We are hopeful that the success we had at Seal in 2006 is only a conservative indication of the ultimate potential of this property.

*Financial Accomplishments*

One of the cornerstones of our strategy for financial sustainability is to fund cash distributions and capital expenditures through internally generated cash flow. We are pleased to have accomplished this objective in 2006.

With the expiry of the lower price WTI oil derivative contracts at the end of 2005, combined with a positive outlook on commodity prices, we increased our monthly distributions by 20 percent from the $0.15 per unit since inception to $0.18 per unit commencing January 2006. Total cash distributed, net of a nine percent participation in our Distribution Reinvestment Plan, amounted to $143 million and represented an industry-leading payout ratio of 52 percent for 2006. Total debt of $364 million at December 31, 2006 was 13 percent lower than one year ago, improving our debt to trailing cash flow ratio to 1.3 from 1.8 a year earlier. No external financings were completed during the year.

Volatility in commodity prices was unabated in 2006, with oil prices and gas prices charting different courses. WTI oil averaged US$66.22 per barrel in the year, a 17 percent increase over the previous record of US$56.56 set in 2005. The Canadian currency, buoyed by healthy commodity prices, also appreciated seven percent against the U.S. currency in 2006, which partially offset the benefits of higher oil price for Canadian producers. Gas prices, on the other hand, declined precipitously from record highs in the beginning of the year to average 18 percent lower than that of 2005. The advantages of Baytex's diversified production mix were apparent as we achieved record cash flow for the year. We are particularly excited about recent and ongoing market developments affecting heavy oil differentials. Lloyd Blend differentials averaged 45 percent of WTI price in the first quarter of 2006, the highest level since the fourth quarter of 2001. However, new pipelines transporting Canadian crude to the U.S. lower mid-west region caused a dramatic reduction in the differentials from April on, resulting in an average differential of 29 percent for the last nine months of the year. Thus far in 2007, differentials have averaged less than 30 percent despite the traditional lower seasonal demand in winter months. Baytex is confident that this trend of improving pricing for Canadian heavy oil will continue as a large number of pipeline and refining projects are underway to further expand the access for Canadian crude in the U.S. markets.

*Market Accomplishments*

Baytex began trading as an income trust on the Toronto Stock Exchange in September 2003. We have paid an aggregate $6.36 per unit of cash distributions to our unitholders to the end of 2006. Our unit price has appreciated from $9.87 in the first month of trading to close at $22.28 on December 31, 2006. Total return since inception was 241 percent. We also began trading on the New York Stock Exchange on March 27, 2006.

Our total return of 38.7 percent to unitholders in 2006 compared favorably to a negative 3.7 percent total return for the TSX/S&P Energy Trust Index, as do our two-year annualized return of 47.2 percent (20.0 percent for the Index) and three-year annualized return of 43.5 percent (23.4 percent for the Index). Our rates of return to unitholders rank us as the best performer among all oil and gas income trusts for each of the one-year, two-year and three-year periods ended on December 31, 2006. We are proud to deliver sustainable success.

*Proposed Tax Fairness Plan*

On October 31, 2006, our federal government announced a "Tax Fairness Plan for Canadians" whereby, among other measures, a tax of 31.5 percent will be imposed on distributions of certain income trusts commencing in 2011. This announcement is in direct contradiction to the explicit commitment not to impose specific taxation on the income trust industry during the last election campaign. The effect on the market was swift and devastating, with income trust investors suffering a collective $30 billion devaluation of their investment.

We believe the government is wrong! Their allegation of tax leakage is arbitrary and unsubstantiated. Their criticism of reduced productivity is a gross generalization and is definitely not applicable to the energy trust sector. Their attempt to level the playing field is ill-conceived and flawed. And, most important of all, their willingness to act against their campaign commitment is disappointing and reprehensible.

The operating history of Baytex provides compelling arguments against the government's positions. Baytex was organized as a corporation from 1993 to 2003. During this period, we grew our business through the reinvestment of all of our cash flow, augmented by numerous debt and equity financings. We did not pay any income tax nor dividends in those 10 years. Since the conversion to an income trust, we have paid out $450 million in distributions, over 90 percent of which is designated as taxable income for our unitholders. As an income trust, we have also invested $600 million in exploration, development and acquisition activities to further our business. We have created income and wealth for our investors. We have contributed economically to our governments and communities. We are engaged in capital intensive projects for resource development to assure sustainability for our entity and for our industry. Our actions clearly do not fit the stereotype trust that our government described as tax-avoiding, productivity-destroying corporate delinquents.

Baytex considers the income trust structure to be a constructive and beneficial vehicle for the energy industry in Canada to manage its maturing oil and gas producing basin. It allows the industry to share the fruits of a healthy commodity price environment directly with income-seeking investors and instill a more responsible level of spending discipline among industry participants. Through

our memberships in the Canadian Association of Income Funds and the Canadian Coalition of Energy Trusts, we will continue to support the efforts to influence the government to amend this proposal to more fairly reflect our contributions to the prosperity of our nation.

*Outlook*

The most important ingredient for a successful organization is its people. During 2006, we made a number of key additions to our senior management team. Mr. Steve Brownridge, who joined Baytex in 1997, was promoted to Vice President, Heavy Oil and Mr. Brett McDonald, who joined us in 2000, was promoted to Vice President, Land. These appointments reflect the past contributions made by these gentlemen and we are pleased to have them assuming a greater role of leadership in our organization. We are also delighted to have Mr. Shaun Paterson and Mr. Mark Smith joining us as Vice President, Marketing and Vice President, Conventional Oil & Gas, respectively. Both Mr. Paterson and Mr. Smith held executive positions with senior energy companies in Calgary and we are fortunate to have them join us to enhance our management capability. Our expanded team has the expertise and experience to lead Baytex in this challenging environment.

Our capital budget of $140 million for 2007 is designed to maintain our production at the 34,000 boe/d level. We are committed to execute our business plans notwithstanding the uncertainty associated with the income trust tax proposal and the recent exceptional volatility in commodity prices. As our cash flow is supported by a balanced production mix, continued improvement in the pricing factors affecting heavy oil differentials, a comprehensive hedging program and a diversified capital structure with excellent liquidity and resources, we are well positioned to fund our capital expenditures and cash distributions internally.

Baytex will be a sustainable and successful oil and gas entity regardless of legal structure. Our fundamentals have never been stronger. We look forward to once again delivering best-in-class performance in the coming year.

On behalf of the Board of Directors

Raymond T. Chan, CA
*President and Chief Executive Officer*
*March 16, 2007*

# Delivering Sustainable Success

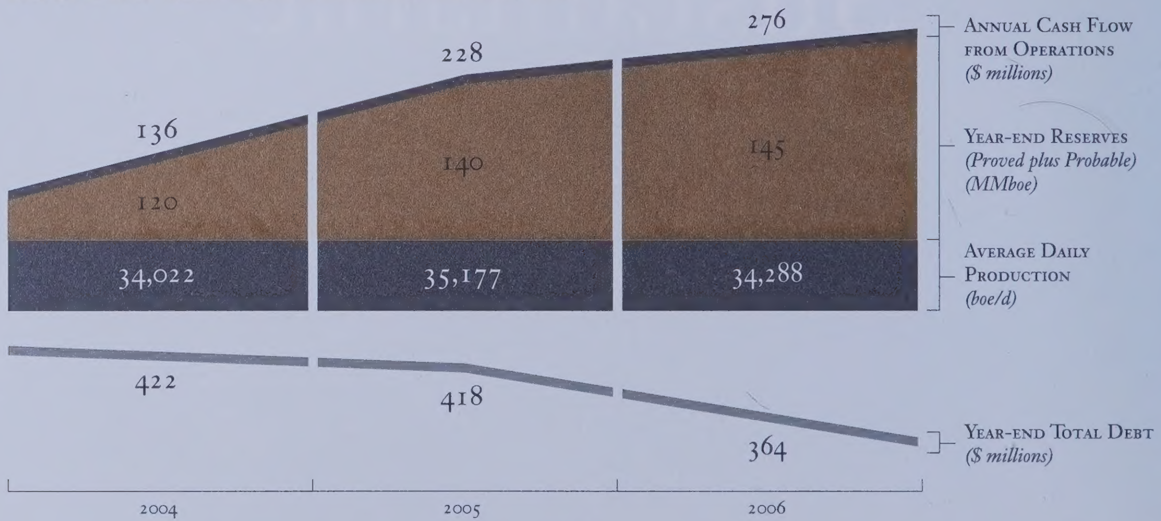
BAYTEX

## BUSINESS PLAN

Our business plan is built around the Technical Expertise as a full cycle exploration and development entity. Our land base offers Quality Development Opportunities, which, combined with Financial Prudence, allow the Trust to be self sustaining both operationally and financially. We manage a multi-year low cost development inventory which offers exposure to a Diversified Product Mix and our competitive advantage in heavy oil offers us a significant exposure to Improving Heavy Oil Pricing Fundamentals.



**SINCE BECOMING A TRUST IN LATE 2003, BAYTEX HAS *DELIVERED EXCEPTIONAL RESULTS.***




## FINANCIAL PRUDENCE

All oil and gas producers have benefited from rising commodity prices, but Baytex has prudently utilized its improving cash flow. At the beginning of 2006, Baytex announced a significant and sustainable distribution increase of 20%. More importantly for the long-term future of Baytex, we have funded a successful capital program while actively managing our debt levels in order to maintain financial flexibility and a strong balance sheet.

How is Baytex delivering

# SUSTAINABLE SUCCESS?

By executing a disciplined business plan.



## TECHNICAL EXPERTISE

Baytex has a full complement of technical and professional staff and assigned multidisciplinary teams working on each of our major assets. This technical focus has allowed us to identify, capture and exploit high-quality development opportunities in a diversified portfolio. These technical skills applied to our land base have resulted in superior profitability for Baytex since conversion to a Trust.

Our results demonstrate our superior success. Oil and gas businesses can only create value if they can sell a barrel of production for net proceeds in excess of the costs to obtain it. Baytex has been able to add reserves at industry-leading finding, development and acquisition costs resulting in outstanding recycle ratios not only for 2006, but for every year since we became a Trust.

## WHERE DO WE GO FROM HERE?

In the near term, we are particularly well positioned to benefit from the improving fundamentals of the heavy oil markets. Let us show you what is improving, and how we will take advantage of it.

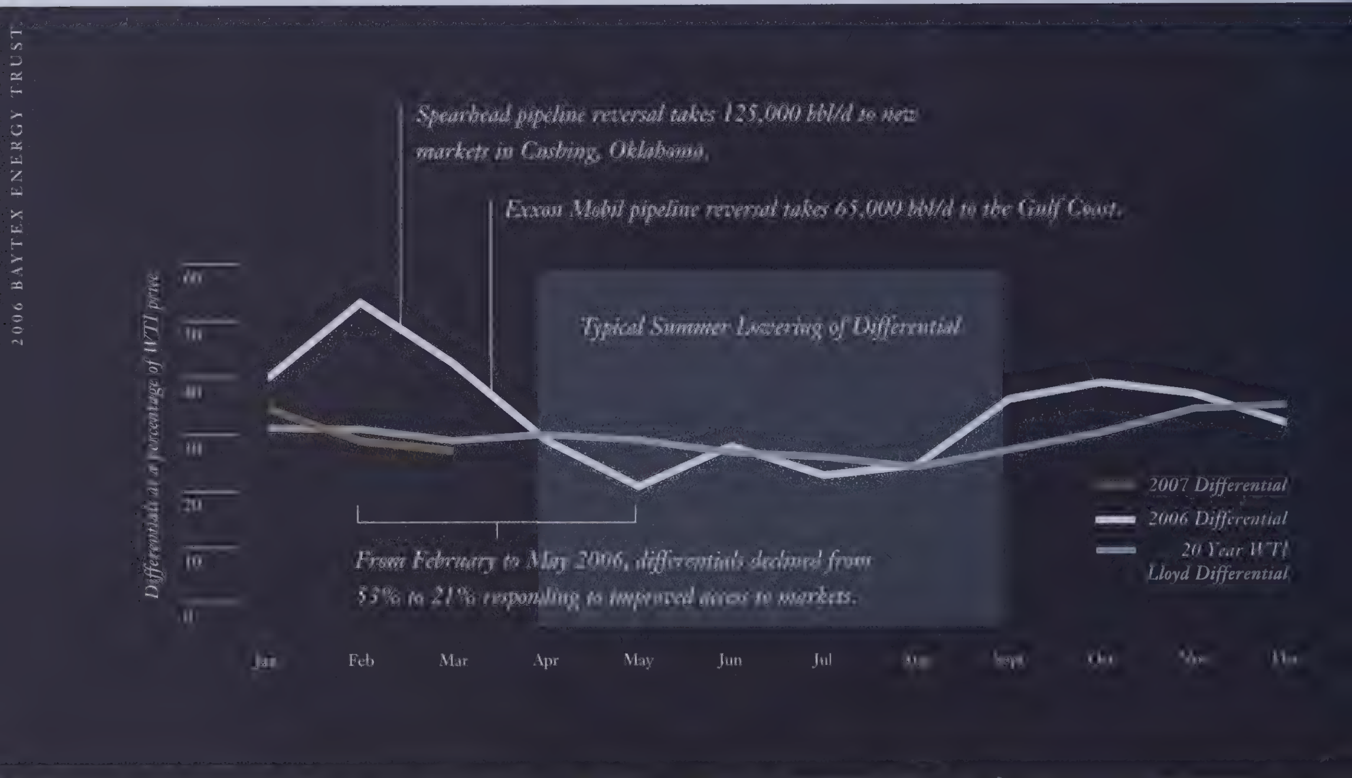
| | 2006 | 3 Year Average 2004 – 2006 |
|---|---|---|
| Operating Netback *($/boe)* | $ 26.75 | $ 22.91 |
| FD&A Costs *(proved plus probable)* | | |
| Exploration and development | $ 7.34 | $ 8.16 |
| Acquisitions | 3.89 | 6.22 |
| Total FD&A Cost per boe | $ 7.31 | $ 7.36 |
| Recycle Ratio | 3.7 | 3.1 |

## IMPROVING HEAVY OIL PRICING FUNDAMENTALS

Heavy oil historically commands a lower selling price than other qualities of crude oil. As the balance of Canadian oil production shifts to heavy oil, refiners and shippers are focusing on infrastructure investments which are having the effect of improving markets for Canadian heavy oil producers. In 2006, two major pipeline projects came onstream providing access to new markets, and their impact was to immediately and dramatically reduce the pricing discount associated with Canadian heavy oil.








The dramatic reduction in the differentials for heavy oil during 2006 demonstrates the response to the improved access for Canadian heavy oil to additional U.S. refining regions. This trend is continuing thus far in 2007. We believe this environment is sustainable as there are numerous pipeline and refining projects being undertaken over the next few years to further expand the markets for Canadian crude both in North America and overseas.


# INFRASTRUCTURE

## improving to access new heavy oil markets

**EXISTING MAJOR PIPELINES**

1. *Express*
2. *Platte*
3. *Enbridge*
4. *AOSPL*
5. *TransMountain*

**2006 PIPELINE REVERSALS**

6. *Spearhead (125 Mbbl/d)*
7. *Exxon Mobil (80 Mbbl/d)*

**PROPOSED FUTURE PIPELINE**

8. *Gateway (400 Mbbl/d, 2010)*
9. *TransCanada Alberta to California (400 Mbbl/d, 2011)*
10. *Kinder Morgan Phase 1 (75 Mbbl/d, 2008)*
11. *Kinder Morgan Phase 2 (100 Mbbl/d, 2009)*
12. *Kinder Morgan Phase 3 (450 Mbbl/d, 2013)*
13. *Waupisoo (350 Mbbl/d, 2008)*
14. *Altex (250 Mbbl/d, 2010)*
15. *Keystone (435 Mbbl/d, 2009)*
16. *Alberta Clipper (400 Mbbl/d, 2010)*
17. *Southern Access (400 Mbbl/d, 2009)*
18. *Express Bullet (400 Mbbl/d, 2010)*

Baytex is well positioned to benefit from the improving heavy oil market. A major heavy oil opportunity for the Trust is our highly prospective Seal property. Baytex currently owns and operates a 100 percent working interest in approximately 100 sections of long-term oil sands leases in the Peace River oil sands area of northwestern Alberta. Starting in 2001, Baytex has patiently built its position at Seal and in 2007 is planning to significantly ramp up production.

EVOLUTION OF THE SEAL PROJECT

1 PLAY IDENTI-FICATION

2 EARLY STAGES

3 2006 ACTIVITY

4 FUTURE PLANS

# QUALITY DEVELOPMENT

## Opportunities – Heavy Oil Resource Play at Seal

**1) 2001 to 2004**

- *Acquired 96 sections of 100 percent owned and operated land at Seal*
- *Completed geological and geophysical work and identified drilling locations*
- *Drilled seven stratigraphic test wells*

**2) 2005**

- *Added an additional four sections of Seal land*
- *Drilled four stratigraphic test wells and six horizontal producing wells*
- *Production averaged 500 bbl/d*
- *Booked 4 MMbbl of proved plus probable reserves*

**3) 2006**

- *Drilled three stratigraphic test wells and two horizontal producing wells*
- *Increased average production to 550 bbl/d from eight producing wells*
- *Initiated long haul trucking to heavy oil market at Chauvin, Saskatchewan using internal trucking operations*
- *Proved plus probable reserves grew to 13 MMbbl*
- *Initiated reservoir simulation study of enhanced oil recovery potential*

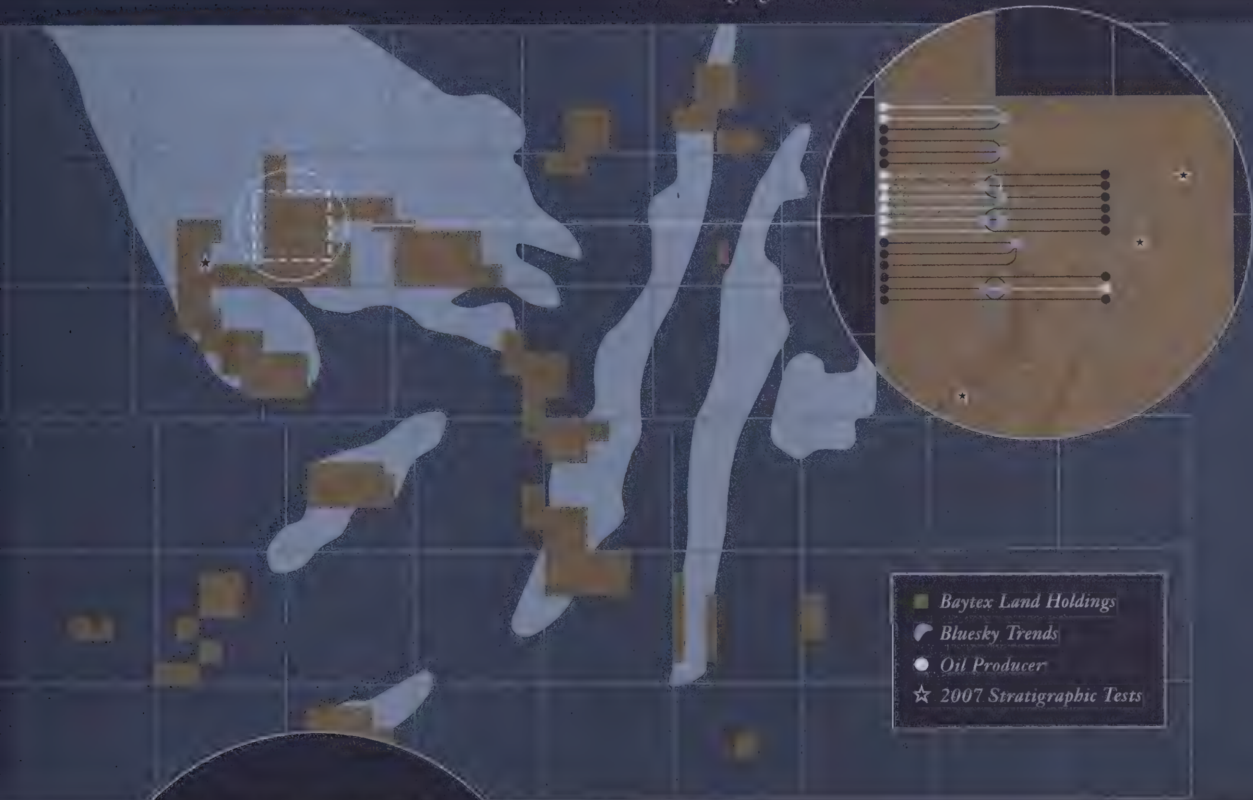
**4) 2007 PLANS**

- *18 new producing wells and four stratigraphic test wells planned*
- *Average daily production budgeted at 1,500 bbl/d, with budgeted exit rate of 2,200 bbl/d*
- *Planning for enhanced oil recovery test in late 2007*

## SIGNIFICANT RESOURCE POTENTIAL

We believe that the Seal property has significant resource potential estimated at 50 MMbbl of original oil in place ("OOIP") for each section of land which ultimately proves to be prospective. To date, Baytex has developed this property using conventional development techniques, which would typically recover three to four percent of the OOIP. Economics on this property on a conventional basis are very compelling, with an average well costing approximately $1.1 million to drill, tie in and equip, and initial production rates averaging 150 bbl/d.







## ENHANCED RECOVERY POTENTIAL

Baytex believes there is significant reserves potential for future development using enhanced recovery techniques, such as waterflood or thermal recovery, which have the potential to increase ultimate recovery factors up to 25 percent of the OOIP. Baytex has methodically tested and developed this property and, in 2007, is planning to commence its first enhanced oil recovery test at Seal.

## DIVERSIFIED PRODUCT MIX

Baytex's heavy oil operations are complemented by significant contributions to production and cash flow from our light oil and natural gas operations. Our production mix has been relatively constant since conversion to a Trust.

As an income Trust, Baytex is keenly aware of the need to maintain a consistent and reliable cash flow profile. Protection from commodity price volatility is managed by Baytex through a combination of heavy oil differential management

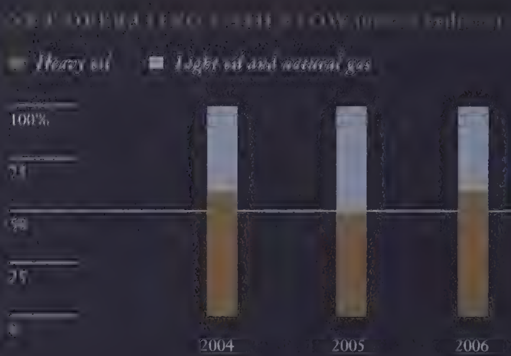


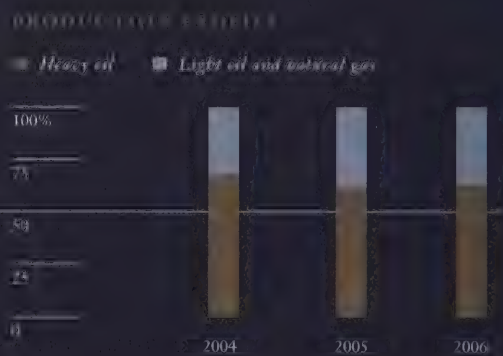


On a product basis, our

# PORTFOLIO BALANCE

provides effective risk management




with the Frontier contract, base commodity price hedging, and with a diversified product mix. While production is weighted towards heavy oil, our cash flow is balanced by strong contributions from our light oil and natural gas assets.

## [illegible]

The lifeblood of an oil and gas company is its inventory of future development projects, which are required to replace natural decline in production. Baytex's high-quality asset base, coupled with a technically-intensive approach to investment project identification and evaluation, has yielded a long-term inventory of future development projects.

Our investment inventory has three key characteristics:

**Size** We have approximately 500 identified future drilling locations, or roughly four years worth at our current drilling pace. Our inventory of future locations has grown every year for the past three years, illustrating that we have been able to add future projects at a faster pace than our investment program has consumed them.

**Balance** Our project inventory is divided between heavy oil and light oil/natural gas projects in roughly the same proportions as our current production mix, which should enable us to sustain our diversified product mix.

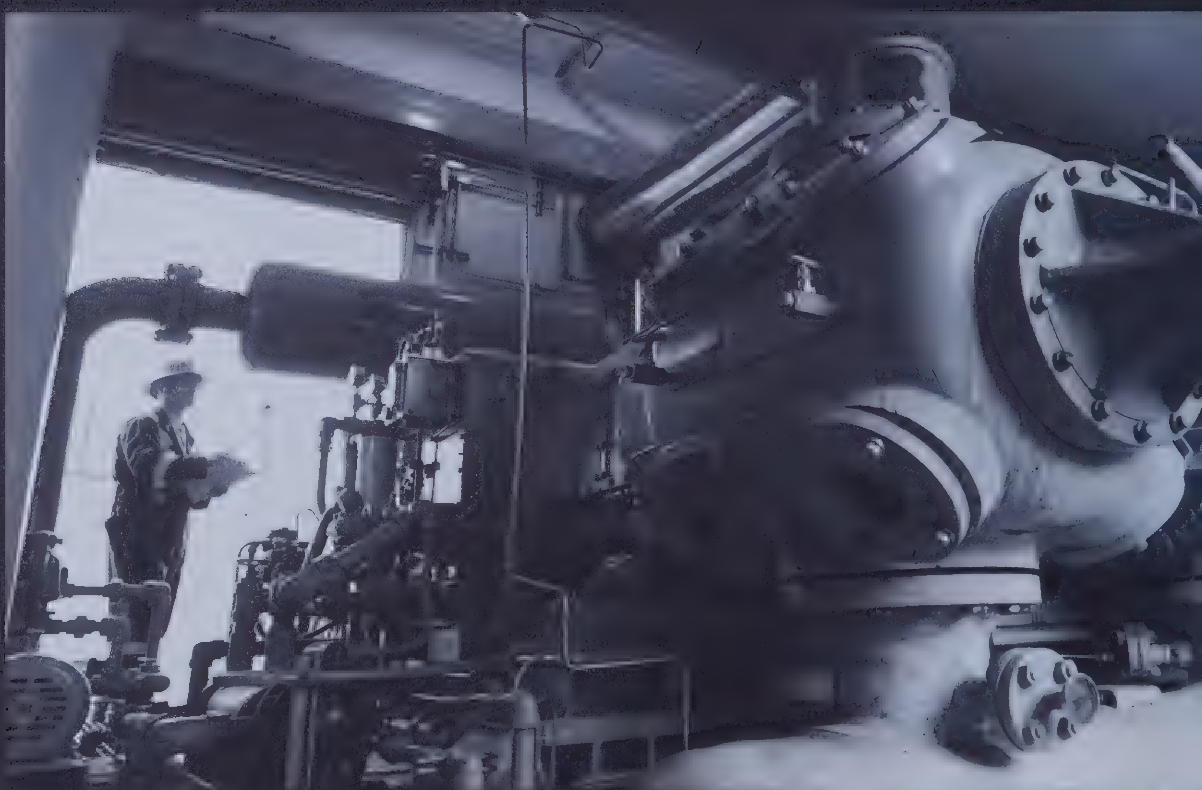
**Economic [illegible]** The expected productivity of the drilling locations in our investment inventory has been increasing over the past three years. Consequently, we have been able to maintain low F&D costs, high recycle ratios and constant production with low levels of capital reinvestment, despite cost pressures that are eroding returns in the rest of the oil and gas industry.

The development and expansion of a large, balanced and robust investment inventory has been central to our sustainable success.

## [illegible]ENTURES TEAM

Baytex has a grass roots exploration program to add new core areas to our property portfolio, primarily targeting light oil and natural gas at the low-to-medium end of the risk spectrum. Our objective is to add one to two high-quality exploration plays to our portfolio each year.

We believe this grass roots program will enhance our long-term sustainability, growth and product mix diversification by providing additional light oil and natural gas project inventory.



## 2006 HIGHLIGHTS

2006 was an outstanding year for Baytex. Improving oil prices, stable production and efficient operations combined to generate record cash flow of $275 million and record net income of $147 million. We once again executed a highly successful capital program replacing 145 percent of the year's production, extending our reserve life index to 11.6 years and increasing our proved plus probable ("P+P") reserves to 145 million barrels of oil equivalent ("boe"). This was accomplished by spending only $133 million during the year, less than half of our operating cash flow.



# Management's Discussion & Analysis

In 2006, Baytex delivered on all fronts. Operationally, production was maintained and reserves were replaced at industry-leading efficiencies. Financially, the Trust funded its capital program and distributions with internally generated cash flow and reduced its total debt. In the investment community, Baytex was the best performer amongst all oil and gas trusts.

The year's finding development and acquisitions costs of $7.31 per boe on P+P basis will be amongst the best in our industry. This year's FD&A costs compare well to our three-year average FD&A costs of $7.37 per boe, and are a clear demonstration of our ability to consistently deliver reserves replacement costs at rates which will ensure our profitability for years to come. Our unitholders have benefited from our results, enjoying a 20 percent increase in distributions over prior years, and combining with a significant appreciation in our unit price generated a 39 percent total return in 2006.

# MANAGEMENT'S DISCUSSION & ANALYSIS

*In 2006, our business plan was met with great success. We generated record cash flow, increased our distributions and replaced our production.*

The following Management's Discussion and Analysis ("MD&A"), dated March 9, 2007, should be read in conjunction with Baytex Energy Trust's (the "Trust" or "Baytex") audited consolidated financial statements for the fiscal years ended December 31, 2006 and 2005. Per barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

The Trust evaluates performance based on net income and cash flow from operations. Cash flow from operations and cash flow per unit are not measurements based on generally accepted accounting principles ("GAAP"), but are financial terms commonly used in the oil and gas industry. Cash flow represents cash generated from operating activities before changes in non-cash working capital, deferred charges and other assets and deferred credits. The Trust's determination of cash flow may not be comparable with the calculation of similar measures for other entities. The Trust considers cash flow from operations a key measure of performance as it demonstrates the ability of the Trust to generate the cash flow necessary to fund future distributions to unitholders and capital investments. The most directly comparable measure calculated in accordance with GAAP is cash flow from operating activities, and net income per unit. A reconciliation of net income to cash flow from operations and cash flow from operating activities is shown under Quarterly Information.

The Trust also uses certain key performance indicators and industry benchmarks such as operating netback ("netback"), finding, development and acquisition costs ("FD&A"), recycle ratio and total capitalization to analyze financial and operating performance. These key performance indicators and benchmarks as presented do not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other entities.

This MD&A contains forward-looking statements relating to future events or future performance. In some cases, forward-looking statements can be identified by terminology such as "may", "will", "should", "expects", "projects", "plans", "anticipates" and similar expressions. These statements represent management's expectations or beliefs concerning,

among other things, future operating results and various components thereof or the economic performance of the Trust. The projections, estimates and beliefs contained in such forward-looking statements necessarily involve known and unknown risks and uncertainties, including the business risks discussed in the MD&A as at and for the years ended December 31, 2006 and 2005, which may cause actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements. Readers should not place undue reliance on any such forward-looking statements, which speak only as of the date they were made. Except where required by securities legislation, the Trust is not obligated to publicly update or revise the forward-looking statements relating to future events or future performance to reflect any change in management's expectations or events.

Baytex Energy Trust was established on September 2, 2003 under a Plan of Arrangement. The Trust is an open-ended investment trust created pursuant to a trust indenture. Subsequent to the Plan of Arrangement, Baytex Energy Ltd. (the "Company") is a subsidiary of the Trust.

Prior to the Plan of Arrangement, the consolidated financial statements included the accounts of the Company and its subsidiaries and partnership. After giving effect to the Plan of Arrangement, the consolidated financial statements have been prepared on a continuity of interests basis which recognizes the Trust as the successor to the Company. The consolidated financial statements include the accounts of the Trust and its subsidiaries and have been prepared by management in accordance with Canadian generally accepted accounting principles.

### 2006 OVERVIEW

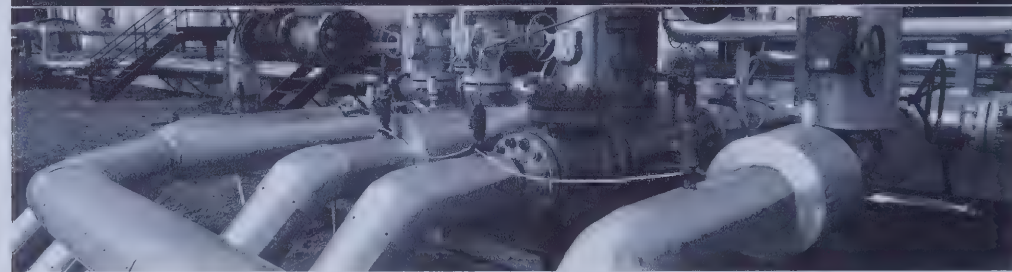
The Trust strives to be self-sustaining from an operational and financial perspective, relying primarily on internal property development to provide production and reserve replacement. The Trust plans to fund its program along with distributions substantially from internally generated cash flow. During 2006, the Trust executed a successful capital program, replacing 145 percent of production (on a proved plus probable basis) by spending less than 50 percent of cash flow from operations. The Trust also increased its monthly distributions from $0.15 per unit to $0.18 per unit beginning in January 2006.

On March 27, 2006, Baytex commenced trading on the New York Stock Exchange. The NYSE listing is being maintained in conjunction with our listing on the Toronto Stock Exchange, and contributes to providing enhanced liquidity to our unitholders.

On October 31, 2006, the Minister of Finance of Canada announced the "Tax Fairness Plan For Canadians" which included a proposal to tax the distributions made by certain income trusts commencing 2011. This proposal is not yet enacted, and as such, no provision for this new tax has been incorporated in the financial statements and discussion presented herein.

# PROPERTY REVIEW

*Each of the Heavy Oil and Light Oil and Natural Gas Districts has an extensive portfolio of operated properties and development prospects with considerable upside potential.*





*Oil and Natural Gas Properties*

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2006. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2006. Well counts indicate gross wells, except where otherwise indicated. Production information represents average working interest production, for the year ended December 31, 2006, except where otherwise indicated.

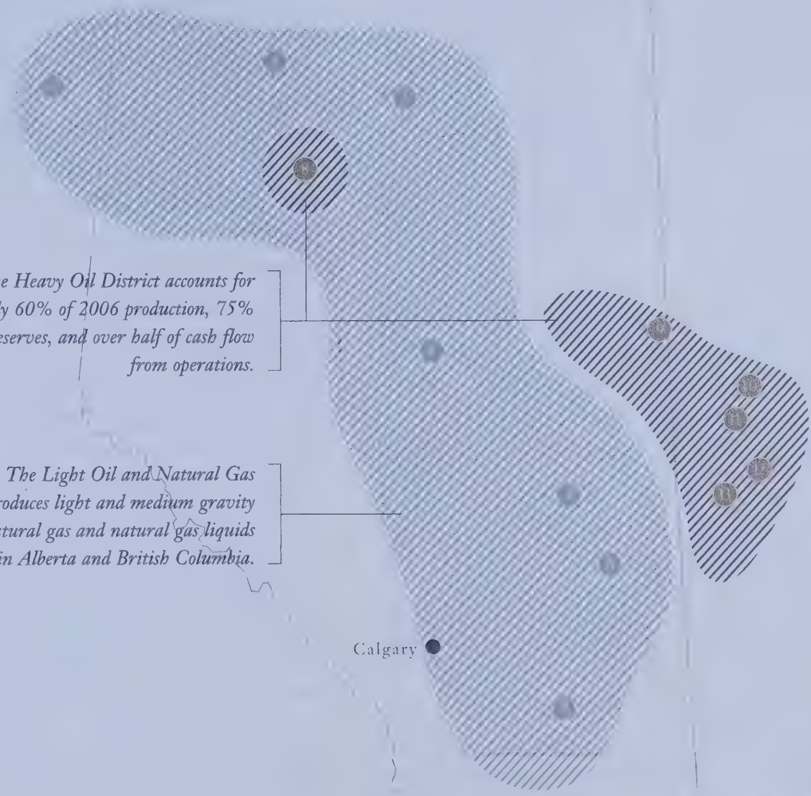
Baytex's crude oil and natural gas operations are organized into two operating districts: the Heavy Oil District and the Light Oil and Natural Gas District. Each district has an extensive portfolio of operated properties and development prospects with considerable upside potential. Within these districts, Baytex has established a total of nine geographically-organized teams with a full complement of technical professionals (engineers, geoscientists and landmen) within each team. This comprehensive technical approach results in thorough identification and evaluation of exploration, development and acquisition investment opportunities, and cost-efficient execution of those opportunities.

*Heavy Oil District*

The Heavy Oil District accounts for approximately 60 percent of current production, three-quarters of oil-equivalent reserves and over half of Baytex's cash flow from operations. Baytex's heavy oil operations consist predominantly of cold primary production, without the assistance of steam injection. In some cases, Baytex's heavy oil reservoirs containing lower-than-average viscosity crudes are waterflooded, occasionally with hot water. Baytex's heavy oil fields often have multiple productive zones, some of which can be commingled within the same producing wellbore. Production is generated from vertical, slant and horizontal wells using progressive cavity pumps capable of handling large volumes of heavy oil combined with gas, water and sand. Initial production from these wells usually averages between 40 and 100 bbl/d of crude with gravities ranging from 11° to 18° API. Once produced, the oil is trucked or pipelined to markets in both Canada and the United States. Heavy crude is usually blended with a light-hydrocarbon diluent (such as condensate) prior to being introduced into a sales pipeline. The blended crude oil is then sold by Baytex and may be upgraded into lighter grades of crude or refined into petroleum products such as fuel oil, lubricants and asphalt by the crude purchasers. All production rates reported are for heavy crude only, before the addition of diluent.

In 2006, production in the Heavy Oil District averaged approximately 21,300 bbl/d of heavy oil and 8.8 MMcf/d of natural gas (22,800 boe/d). Baytex drilled 88 gross (84.2 net) wells in the Heavy Oil District resulting in 79 (75.2 net) oil wells, four (4.0 net) gas wells, three (3.0 net) stratigraphic test wells, and

*Baytex's crude oil and natural gas operations are organized into two operating districts – the Heavy Oil District and the Light Oil and Natural Gas District.*




*The Heavy Oil District accounts for approximately 60% of 2006 production, 75% of reserves, and over half of cash flow from operations.*

*The Light Oil and Natural Gas District produces light and medium gravity crude oil, natural gas and natural gas liquids from fields in Alberta and British Columbia.*

## BAYTEX KEY PROPERTIES

**Light Oil & Natural Gas**

- Stoddart
- Nina/Darwin
- Red Earth/Goodfish
- Bon Accord
- Leahurst
- Garden Plains/Sedalia
- Turin

**Heavy Oil**

- 8 Seal
- 9 Ardmore/Cold Lake
- 10 Celtic
- 11 Tangleflags
- 12 Carruthers
- 13 Marsden/Epping

*Baytex has established several geographically-organized teams with a full complement of technical professionals (engineers, geoscientists and landmen) within each team. This comprehensive technical approach results in thorough identification and evaluation of exploration, development and acquisition opportunities and cost-efficient execution of those opportunities.*

two (2.0 net) dry and abandoned wells, for a success rate of 97.7 percent (97.6 percent net).

The Heavy Oil District possesses a large inventory of development projects within the west-central Saskatchewan, Cold Lake/Ardmore, and Peace River areas. Baytex's ability to generate relatively low-cost replacement production through conventional cold production methods is key to maintaining the Trust's overall production rate. Because of Baytex's large inventory of heavy oil investment projects, the Trust is able to select between a wide range of investments to maintain heavy oil production rates.

Baytex will continue to build value through internal heavy oil property development and selective acquisitions. Future heavy oil development will focus both on the Peace River Oil Sands area and Baytex's area of historical emphasis around Lloydminster in southwestern Saskatchewan and southeastern Alberta. Our net undeveloped lands in the Heavy Oil District totaled approximately 294,492 acres at year-end 2006.

ARDMORE, ALBERTA: Acquired in 2002 at a production rate of 2,200 bbl/d, this property has since been extensively developed in the Sparky, McLaren and Colony formations. Average production during 2006 was approximately 3,100 bbl/d of oil and 500 Mcf/d of natural gas (3,200 boe/d). Eleven successful oil wells and no dry holes were drilled in the area during 2006. Baytex anticipates drilling two wells in this area in 2007. In addition, new production techniques, such as cold horizontal well production and cyclic steam injection are being evaluated for the large hydrocarbon resource in this area. Due to extensive Baytex infrastructure in this area, operating expenses in 2006 remained relatively low at approximately $6.00 per boe. Net undeveloped lands were 41,800 acres at year-end 2006.

CARRUTHERS, SASKATCHEWAN: The Carruthers property was acquired by Baytex in 1997. This property consists of separate "North" and "South" oil pools in the Cummings formation. During 2006, average production was approximately 2,400 bbl/d of heavy oil and 900 Mcf/d of natural gas (2,500 boe/d). Although no new wells were drilled in this area in 2006, a significant hot waterflood expansion (upgrading battery treating capacity, conversion of six wells to injection and restarting 11 producing wells) was completed. Net undeveloped lands were 9,700 acres at year-end 2006.

CELTIC, SASKATCHEWAN: This producing property was acquired in October 2005, in a transaction which included approximately 2,000 bbl/d of Steam Assisted Gravity Drainage (SAGD) production. The SAGD production was divested at the end of 2005, leaving Baytex with purchased cold heavy oil production of 1,600 bbl/d and 0.9 MMcf/d. As a result of Baytex's well recompletion and drilling activities, cold production increased to an average of 3,800 bbl/d of heavy oil and 1.9 MMcf/d of natural gas (4,100 boe/d) during 2006. (This production number includes Baytex production in the area held prior to the Celtic acquisition). Celtic is a key asset for Baytex because, like the adjacent Tangleflags property, it contains a large resource base within multiple prospective horizons. As a result, the Celtic property provides a multi-year inventory of drilling locations and recompletion opportunities. Also like Tangleflags, the heavy oil at Celtic is relatively highly gas-saturated and the existing infrastructure allows for efficient capture and marketing of co-produced solution gas. In 2007 Baytex expects to drill 20 new wells and recomplete up to 60 existing wells. Net undeveloped lands were 8,700 acres at year-end 2006.

COLD LAKE, ALBERTA: Located on Cold Lake First Nations lands, this heavy oil property was acquired by Baytex in 2001. Production is primarily from the Colony formation. Average oil production during 2006 was approximately 600 bbl/d, during which time Baytex drilled four oil wells. In 2006, Baytex acquired additional mineral rights to capture deeper producing horizons on 7,680 acres of land on which it already held shallow leases. These new rights are anticipated to ultimately generate up to 15 new drilling locations, and three new wells are planned for 2007. Net undeveloped lands were 15,300 acres at year-end 2006.

MARSDEN/EPPING/MACKLIN/SILVERDALE, SASKATCHEWAN: This area of Saskatchewan is characterized by low access costs and generally higher quality crude oil that ranges up to 18° API. Initial

per well production rates are typically 40 to 70 bbl/d. Primary recovery factors can be as high as 30 percent of the original oil in-place because of the relatively high oil gravity and the existence of strong water drive in many of the oil pools in this area. Average oil production in this area during 2006 was approximately 4,200 bbl/d and 950 Mcf/d (4,400 boe/d). Eleven oil wells were drilled in 2006. During 2007, nine new wells are planned for this area, as well as an expansion of the solution gas sales facility at Macklin. Net undeveloped lands were 19,300 acres at year-end 2006.

SEAL, ALBERTA: Seal is a highly prospective property located in the Peace River Oil Sands area of northern Alberta. Baytex holds a 100 percent working interest in over 100 sections of long-term oil sands leases. In certain parts of this land base, heavy oil can be produced through primary methods using horizontal wells at initial rates of approximately 150 bbl/d per well, without employing more capital-intensive methods such as steam injection. During 2006, Baytex drilled three new stratigraphic test wells to identify extensions to our current development area located on the western block of these land holdings. In this area, Baytex also drilled two new horizontal producing wells, bringing the total number of producing wells to eight. Average production rate during 2006 was 550 bbl/d of heavy oil. Baytex plans to drill four additional stratigraphic test wells and up to 18 horizontal producing wells at Seal during 2007. Baytex is also core-testing and conducting numerical reservoir simulation of both waterflood and cyclic steam recovery methods for Seal. Both of these processes have the potential to greatly increase ultimate recovery factor beyond what is achievable with primary recovery. We anticipate conducting a steam injection field test by 2008 or earlier. Operators of adjoining lands are also pursuing aggressive development programs that will contribute to vital infrastructure and allow enhanced marketing solutions for the region. As the region continues to develop, the Seal property will take an increasingly more prominent role in the Trust's production profile. Net undeveloped lands in this area were 66,200 acres at year-end 2006.

TANGLEFLAGS, SASKATCHEWAN: Baytex acquired the Tangleflags property in 2000. Tangleflags is characterized by multiple-zone reservoirs with production from the Colony, McLaren, Waseca, Sparky, General Petroleum and Lloydminster formations. Accordingly, this property supplies long-term development potential through a considerable number of uphole recompletion opportunities. In 2006, 24 wells were either restarted or recompleted. Average production during 2006 was approximately 2,200 bbl/d of heavy oil and 1.0 MMcf/d of natural gas (2,300 boe/d). In 2007, Baytex plans to drill two new wells and recomplete about 30 existing wells in Tangleflags. Net undeveloped lands were 8,300 acres at year-end 2006.

*Light Oil and Natural Gas District*

Although Baytex is best known as a "heavy oil" energy trust, we also possess a growing array of light oil and natural gas properties that generate nearly half of our cash flow. In addition to Baytex's historical light oil and natural gas properties in northern and southeastern Alberta, the geographic scope of our light oil and gas operations has expanded to southwestern Alberta and northeastern British Columbia, providing exposure to some of the most prospective areas in Western Canada.

The Light Oil and Natural Gas District produces light and medium gravity crude oil, natural gas and natural gas liquids from various fields in Alberta and British Columbia. During 2006, production from this district averaged 47 MMcf/d of natural gas sales and 3,700 bbl/d of light oil and NGLs for annual average oil equivalent production of 11,500 boe/d. In 2006, the Light Oil and Natural Gas District drilled 40 (33.4 net) wells resulting in 17 (14.1 net) gas wells, 19 (16.1 net) oil wells, and four (3.2 net) dry wells for a success rate of 90 percent (90.4 percent net). Our net undeveloped lands in this business unit were approximately 323,643 acres at year-end 2006.

BON ACCORD, ALBERTA: This multi-zone property was acquired by Baytex in 1997. Production, which is from the Belly River, Viking and Mannville formations, averaged approximately 4.3 MMcf/d of

sales gas and 300 boe/d of light oil (1,000 boe/d) during 2006. Natural gas is processed at two Company-operated plants and oil is treated at three Company-operated batteries. During 2006, Baytex drilled three gas wells and two oil wells in this area. At year-end 2006, Baytex had 21,400 net undeveloped acres in this area.

DARWIN/NINA, ALBERTA: Both properties in this winter-access area produce natural gas from the Bluesky formation. Natural gas production is processed at two Company-operated gas plants. Production during 2006 averaged approximately 3.5 MMcf/d (600 boe/d). During 2006, Baytex drilled three gas wells in this area. Baytex plans to install an amine facility at Darwin during 2007 to remove carbon dioxide from sales gas and improve operating capability and product netback for the area. At year-end 2006, Baytex had 44,700 net undeveloped acres in this area.

LEAHURST, ALBERTA: Production averaged approximately 3.7 MMcf/d (600 boe/d) sales gas in 2006 from this multi-zone, year-round access area. Natural gas from the Edmonton, Belly River, Viking and Mannville formations is processed at several plants, one of which is Company-operated. During 2006, Baytex drilled one gas well and one abandoned well in this area. During 2007, Baytex plans to drill up to six wells in this area. At year-end 2006, Baytex had 15,600 net undeveloped acres in this area.

RICHDALE/SEDALIA, ALBERTA: In 2001, Baytex acquired its initial position in this area and significantly increased its presence with a 2004 acquisition of a private company. During 2006, production averaged approximately 7.7 MMcf/d of gas (1,300 boe/d). This area has advantages of year-round access and multi-zone potential in the Second White Specks, Viking and Mannville formations. Most of the gas production from this area is processed at two Company-operated gas plants. During 2006, Baytex drilled four gas wells in this area and plans to drill four to seven additional wells during 2007. At year-end 2006, Baytex had 41,800 net undeveloped acres in this area.

RED EARTH/GOODFISH, ALBERTA: This primarily winter-access, multi-zone property was acquired by Baytex in 1997. Oil production from Granite Wash and Slave Point pools is treated at two Company-operated sweet oil batteries. Natural gas production from the Bluesky formation is handled at two gas plants, one of which is Company-operated. Production from this area during 2006 averaged approximately 5.3 MMcf/d sales gas and 700 bbl/d of hydrocarbon liquids (1,600 boe/d). During 2006, Baytex drilled two gas wells and one abandoned well in this area. At year-end 2006, Baytex had 33,900 net undeveloped acres in this area.

TURIN, ALBERTA: This multi-zone, year-round access property was acquired in 2004 with the acquisition of a private company. Production during 2006 averaged approximately 700 bbl/d of oil and NGLs and 1.8 MMcf/d sales gas (1,000 boe/d). Production is from the Second White Specks, Milk River, Bow Island, Mannville, Sawtooth and Livingstone formations. Oil production is treated at three Company-operated batteries and gas is processed at two outside-operated gas plants. During 2006, Baytex drilled two gas wells and five oil wells in this area. Baytex plans to drill three to six wells in the Turin area during 2007. At year-end 2006, Baytex had 14,600 net undeveloped acres in this area.

STODDART, BRITISH COLUMBIA: The Stoddart asset acquisition was completed in December 2004. Oil and liquids rich gas production from this largely year-round-access area comes from the Doig, Halfway, Baldonnel, Coplin and Bluesky formations. Oil is treated at two Company-operated batteries and natural gas is compressed at four Company-operated sites and sent for further processing at the outside-operated West Stoddart and Taylor Younger plants. Production from this area during 2006 averaged approximately 12.5 MMcf/d sales gas and 1,900 bbl/d of oil and NGLs (4,000 boe/d). Baytex drilled nine wells in 2006 resulting in two gas wells, six oil wells and one abandoned well. Baytex plans to drill up to eight wells and recomplete several wells in 2007. At year-end 2006, Baytex had 31,400 net undeveloped acres in this area.

# MARKETING

*[illegible]*

*Crude Oil*

World crude oil prices rose again in 2006 as moderate demand growth combined with OPEC production cuts, supply disruptions and geopolitical uncertainty drove prices higher. World demand for oil and products grew by a modest 1.1 percent in 2006 compared to 1.4 percent in 2005, reflecting slower growth in North American and European demand offset by renewed strength in Asian demand. Ample crude oil supply was available during the period, but the threat of supply disruptions due to weather, operating problems and geopolitical events resulted in a fear price premium. When it became apparent that the 2006 hurricane season would not be a repeat of the disastrous events of 2005 and inventories of crude oil and products grew, prices which peaked in August began to drift lower.

The decline in prices subsided in October after OPEC's unexpected announcement that they planned to cut production by 1.2 million barrels per day effective November 1. Geopolitical events again played a role throughout the year as the ongoing conflict in Iraq, unrest in Nigeria, war in Lebanon, politics in Russia and the Iranian nuclear stand-off have left market participants very nervous.

Benchmark West Texas Intermediate (WTI) prices began the year around US$60 per bbl, climbed to an all-time high of US$77.03 in August, and ended the year over US$61. The average price for 2006 was US$66.22 compared to US$56.56 in 2005, an increase of 17 percent. The five-year WTI average is US$44.26 per bbl.

Canadian crude oil prices, while enjoying the strength in world prices, were tempered by the rising Canadian dollar against its U.S. counterpart. Canadian Par crude at Edmonton averaged $72.77 per bbl in 2006, up six percent from $68.75 in 2005. The five-year Canadian par average price is Cdn$55.41 per bbl.

With OPEC cutting oil output late in 2006 to meet their pricing targets, the first volumes shut-in were the lower value medium and heavy sour grades. In addition, the huge Cantarell field which supplies most of Mexico's benchmark Maya export blend is on a steep decline at 10.3 percent through the first half of 2006. This has resulted in reduction in supplies of heavy and medium sour crude oil to the world market, tightening differentials in the latter part of 2006. Canadian heavy oil prices mirrored this trend as the differential between WTI and Lloydminster Blend prices averaged US$22.66 per bbl in 2006 (34 percent of WTI) compared to US$21.82 per bbl in 2005 (39 percent of WTI). The five-year averages are US$14.79 and 32 percent. Our heavy oil prices averaged $43.57 per barrel in 2006, an increase of 17 percent compared to $37.38 in 2005.

Not withstanding all the volatility in underlying index basis and quality price differentials, Baytex's conventional crude oil and natural gas liquids prices averaged $53.84 per bbl in both 2006 and 2005.

In October 2002, Baytex signed a five-year crude oil supply agreement with Frontier Oil and Refining Company ("Frontier") of Houston, Texas. The agreement calls for Baytex to deliver 20,000 barrels per day of Lloydminster Blend ("LLB") quality crude at Hardisty, Alberta for delivery to Guernsey, Wyoming. The blended crude supplied is comprised of approximately 16,000 barrels per day of Baytex raw heavy crude oil and 4,000 barrels per day of purchased condensate used as diluent. Prices are fixed at 71 percent of WTI translating into a LLB quality differential at 29 percent of WTI. This mirrored the long-term average differential dated back to 1986. This contract significantly reduces the volatility of Baytex's cash flows from heavy crude oil sales.

Baytex has entered into a series of costless collar derivative contracts which will provide significant downside protection on oil price while still allowing us to participate in market upside potential. Contracts have been put in place for 2007 on 8,000 barrels per day at a weighted average price between US$56.88 per bbl to US$82.48 per bbl. No collars have yet been implemented for 2008.

The market and infrastructure solutions for our Seal area remain a work in progress. Management is confident that long-term solutions will be developed to allow full-scale field development commencing in 2007.

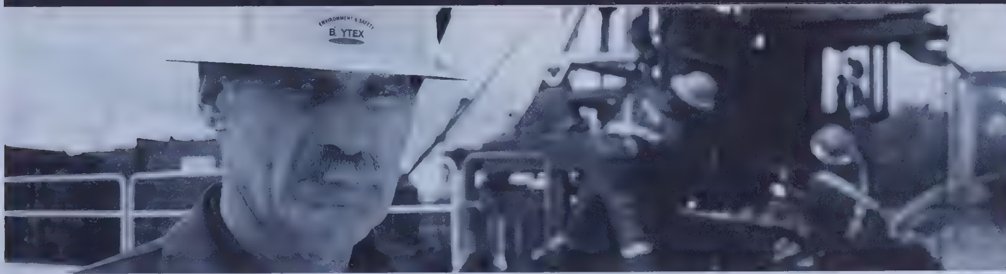
*Natural Gas*

Natural gas prices in North America weakened in 2006, reflecting strong supply availability. High oil prices sustained gas values at levels that might have been much lower in a lower alternative energy price environment. U.S. inventories were at historically high levels throughout the year due to low demand and the lack of any supply disruptions as suffered during the 2005 hurricane season. U.S. gas prices, represented by the NYMEX futures contract, averaged US$7.27 per thousand cubic feet (Mcf) in 2006, a decrease of 15 percent from US$8.55 in 2005. Daily prices for Alberta gas delivered to the AECO "C" trading hub averaged $6.51 per Mcf in 2006, down 25 percent from $8.71 in 2005.

The five-year averages are US$6.12 per Mcf for the NYMEX contract, and $6.49 for Alberta daily prices. Baytex received an average of $7.13 per Mcf for 2006 natural gas sales compared to $8.22 in 2005.

For 2007 Baytex has entered into several physical forward sales contracts with price collars. Contracted volumes totaled 14.2 MMcf/d during the first quarter of 2007 with an average floor price of $8.44 per Mcf and an average ceiling price of $10.23 per Mcf. Contracts totaling 16.1 MMcf/d for the period of April to October 2007 are also in place with an average floor price of $7.02 per Mcf and an average ceiling price of $9.39 per Mcf.

# OPERATIONS






*Production*

The Trust's average production for fiscal 2006 was 34,292 boe/d compared to 35,177 boe/d for fiscal 2005. Light oil and NGL production decreased by three percent to 3,735 bbl/d from 3,842 bbl/d for last year. Heavy oil production for 2006 was essentially unchanged at 21,326 bbl/d compared to 21,265 bbl/d in 2005. Natural gas production decreased by eight percent to average 55.4 MMcf/d for 2006 compared to 60.4 MMcf/d for 2005. The decrease in light oil, NGL and natural gas volumes was largely due to delayed timing of certain natural gas tie-ins and natural declines. Heavy oil production increased slightly due to development activities and full-year ownership of the properties at Celtic, offset by the sale of the thermal production at year-end 2005.

| *Production by Area* | *Light Oil and NGL* | *Heavy Oil* | *Natural Gas* | *Oil Equivalent* |
|---|---|---|---|---|
| | *(bbl/d)* | *(bbl/d)* | *(MMcf/d)* | *(boe/d)* |
| 2006 | | | | |
| Heavy Oil District | – | 21,325 | 8.8 | 22,791 |
| Light Oil and Natural Gas District | 3,735 | – | 46.6 | 11,501 |
| **Total production** | 3,735 | 21,325 | 55.4 | 34,292 |
| 2005 | | | | |
| Heavy Oil District | – | 21,265 | 7.5 | 22,515 |
| Light Oil and Natural Gas District | 3,842 | – | 52.9 | 12,662 |
| **Total production** | 3,842 | 21,265 | 60.4 | 35,177 |

*Revenue*

Petroleum and natural gas sales for 2006 increased by two percent to $556.7 million from $546.9 million for fiscal 2005. Benchmark WTI crude oil averaged US$66.22 per bbl for 2006, representing a 17 percent increase over the US$56.56 per bbl for 2005. However, the Trust's realized wellhead prices were reduced by a strengthening Canadian dollar, which averaged US$0.8817 in 2006 compared to US$0.8253 in 2005. The Trust's light oil and NGL price remained consistent from prior year at $53.84 per bbl. The heavy oil price increased 17 percent to $43.57 per bbl in 2006 from $37.38 per bbl in 2005. Natural gas prices were 13 percent lower in 2006, averaging $7.13 per Mcf compared to $8.22 per Mcf during the previous year. Overall, after accounting for $2.5 million of realized gain on financial derivative contracts, the Trust averaged $44.68 per boe for 2006, a 15 percent increase from $38.82 per boe received in the prior year.

For 2006, light oil and NGL revenue decreased three percent from the same period last year due to a three percent decrease in production. Revenue from heavy oil increased 17 percent due to increase in wellhead prices. Revenue from natural gas decreased 20 percent compared to 2005, as production decreased eight percent combined with a price decrease of 13 percent.

| *Gross Revenue Analysis* | 2006 | | 2005 | |
|---|---|---|---|---|
| | *$ thousands* | *$/Unit (1)* | *$ thousands* | *$/Unit (1)* |
| Oil revenue *(bbl)* | | | | |
| Light oil & NGL | 73,387 | 53.84 | 75,507 | 53.84 |
| Heavy oil | 339,066 | 43.57 | 290,163 | 37.38 |
| Derivative contract gain (loss) | 2,529 | 0.32 | (48,462) | (6.24) |
| Total oil revenue | 414,982 | 45.38 | 317,208 | 34.61 |
| Natural gas revenue *(Mcf)* | 144,236 | 7.13 | 181,270 | 8.22 |
| Total revenue *(boe)* | 559,218 | 44.68 | 498,478 | 38.82 |

*(1) Per-unit oil revenue is in $/bbl; per unit natural gas revenue is in $/Mcf.*

*Royalties*

For the year ended December 31, 2006, royalties increased to $85.0 million from $81.9 million for last year. Total royalties in 2006 were 15.3 percent of sales, compared to 15.0 percent of sales for 2005. For 2006, royalties were 14.6 percent of sales for light oil and NGL, 14.6 percent for heavy oil and 17.2 percent for natural gas. These rates compared to 15.1 percent, 12.4 percent and 19.0 percent, respectively, for 2005. Royalties are generally based on market index prices realized by the industry in the period, with increasing rates as price and volume escalate. Baytex's increased effective royalty rate for heavy oil in 2006 was reflective of the higher market price.

*Operating Expenses*

Operating expenses for the year 2006 increased to $112.4 million from $110.6 million in 2005. Operating expenses were $8.98 per boe for 2006 compared to $8.62 per boe for the prior year. In 2006, operating expenses were $11.17 per bbl of light oil and NGL, $9.23 per bbl of heavy oil and $1.25 per Mcf of natural gas compared to $9.06, $9.56 and $1.08, respectively, for the year earlier.

*Transportation Expenses*

Transportation expenses for the year ended December 31, 2006 were $24.3 million compared to $22.4 million for 2005. These expenses were $1.95 per boe in 2006 compared to $1.74 in 2005. Transportation expenses were $2.38 per bbl of oil and $0.13 per Mcf of natural gas in 2006, and $2.11 per bbl of oil and $0.14 per Mcf of natural gas in 2005.

*Net Revenue*

| | Light Oil & NGL ($/bbl) | | Heavy Oil ($/bbl) | | Total Oil & NGL ($/bbl) | | Natural Gas ($/Mcf) | | BOE ($/boe) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | **2006** | 2005 | **2006** | 2005 | **2006** | 2005 | **2006** | 2005 | **2006** | 2005 |
| Sales price (1) | **53.84** | 53.84 | **43.57** | 37.38 | **45.10** | 39.90 | **7.13** | 8.22 | **44.48** | 42.60 |
| Royalties | **(7.84)** | (8.13) | **(6.37)** | (4.63) | **(6.59)** | (5.17) | **(1.23)** | (1.57) | **(6.80)** | (6.38) |
| Operating costs | **(11.17)** | (9.06) | **(9.23)** | (9.56) | **(9.52)** | (9.48) | **(1.25)** | (1.08) | **(8.98)** | (8.62) |
| Transportation | **(1.16)** | (1.16) | **(2.60)** | (2.28) | **(2.38)** | (2.11) | **(0.13)** | (0.14) | **(1.95)** | (1.74) |
| Net revenue | **33.67** | 35.49 | **25.37** | 20.91 | **26.61** | 23.14 | **4.52** | 5.43 | **26.75** | 25.86 |

*(1) Sales price is before realized loss/gain recognized on financial derivative contracts.*

*General and Administrative Expenses*

General and administrative expenses for the year were $20.8 million compared to $16.0 million for the prior year. On a per sales unit basis, these expenses were $1.67 per boe in 2006 and $1.25 per boe in 2005. The increase is attributable to escalating costs in the labour market, additional expenses associated with the New York Stock Exchange listing and costs relating to compliance requirements under the Sarbanes-Oxley Act. In accordance with our full cost accounting policy, no expenses were capitalized in either 2006 or 2005.

| *($ thousands)* | **2006** | 2005 |
|---|---|---|
| Gross corporate expense | **28,538** | 22,568 |
| Operator's recoveries | **(7,695)** | (6,558) |
| Net expenses | **20,843** | 16,010 |

*Unit Based Compensation Expense*

Compensation expense related to the Trust's unit rights incentive plan was $7.5 million for 2006 compared to $5.3 million for 2005.

Compensation expense associated with rights granted under the plan is recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. The exercise of trust unit rights are recorded as an increase in trust units with a corresponding reduction in contributed surplus.

Until July 1, 2005, the Trust accounted for stock-based compensation based on the intrinsic value of the awards at each reporting date. Effective July 1, 2005, on a prospective basis, the trust began valuing options using the fair value based method. In the fourth quarter of 2005, the trust determined that the fair value methodology should have been applied to all grants since CICA 3870 was adopted, and the financial statements of prior periods have been restated accordingly.

*Interest Expense*

In 2006, interest expense was $35.0 million compared to $33.1 million for last year. The increase is attributable to a gradual increase in interest rates partially offset by the decrease in outstanding convertible debentures and the effect of a stronger Canadian dollar on U.S. dollar denominated interest expense.

*Foreign Exchange*

The foreign exchange gain for 2006 was $0.1 million compared to $6.8 million in the prior year. The 2006 gain is based on the translation of the U.S. dollar denominated long-term debt at 0.8581 at December 31, 2006 compared to 0.8577 at December 31, 2005. The 2005 gain is based on translation at 0.8577 at December 31, 2005 compared to 0.8308 at December 31, 2004.

*Depletion, Depreciation and Accretion*

Depletion, depreciation and accretion decreased to $152.6 million for 2006 compared to $167.1 million for last year. This decrease is due to a lower depletion rate resulting from the full year impact of low-cost proved reserves added from the Celtic acquisition in the fourth quarter of 2005 and development activities during 2006. On a sales-unit basis, the provision for the current year was $12.19 per boe compared to $13.02 per boe for 2005.

*Taxes*

Current tax expenses were $8.4 million for 2006 compared to $8.7 million last year. The current tax expense is comprised of $8.2 million of Saskatchewan Capital Tax, a recovery of $0.4 million of Large Corporation Tax and $0.6 million prior period adjustment compared to $6.9 million of Saskatchewan Capital Tax and $1.8 million of Large Corporation Tax in 2005.

The fiscal 2006 provision for future income taxes was a recovery of $41.1 million compared to a recovery of $7.1 million for the prior year. The future income tax recovery for 2006 reflected federal legislation introduced decreasing the taxation rates on resource income.

*Canadian Tax Pools*

| *($ thousands)* | **2006** | 2005 |
|---|---|---|
| Cumulative Canadian Exploration Expense | **9,803** | 4,953 |
| Cumulative Canadian Development Expense | **124,111** | 129,596 |
| Cumulative Canadian Oil and Gas Property Expense | **164,781** | 162,974 |
| Undepreciated Capital Cost | **199,504** | 179,009 |
| Other | **28,633** | 31,087 |
| Total tax pools | **526,832** | 507,619 |

*Cash Flow from Operations*

Cash flow from operations in 2006 increased 21 percent to $274.7 million from $227.5 million for the previous year. On a barrel of oil equivalent basis, cash flow from operations was $21.94 for 2006 compared to $17.72 for 2005. The increase is due to higher sales revenue and a lower realized loss from financial derivative contracts in 2005.

| *Cash Flow Netbacks* | **2006** | | 2005 | |
|---|---|---|---|---|
| | *$/boe* | *Percent* | *$/boe* | *Percent* |
| Production revenue | **44.48** | **100** | 42.60 | 100 |
| Derivative contract loss | **0.20** | **–** | (3.77) | (9) |
| Royalties | **(6.79)** | **(15)** | (6.38) | (15) |
| Operating expenses | **(8.98)** | **(20)** | (8.62) | (20) |
| Transportation | **(1.95)** | **(4)** | (1.74) | (4) |
| Operating netback | **26.96** | **61** | 22.09 | 52 |
| General and administrative expenses | **(1.67)** | **(4)** | (1.25) | (3) |
| Interest expense | **(2.68)** | **(6)** | (2.44) | (6) |
| Current income taxes | **(0.67)** | **(2)** | (0.68) | (1) |
| Cash flow netback | **21.94** | **49** | 17.72 | 42 |

*Net Income*

Net income for 2006 was $147.1 million compared to $79.9 million for 2005. The increase was attributable to the elimination of realized loss from financial derivatives, lower depletion and depreciation, and a higher future income tax recovery.

*Capital Expenditures*

Capital expenditures during 2006 totaled $133.1 million, with $132.4 million spent on exploration and development activities and $0.7 million spent on acquisitions net of dispositions of assets.

For the year ended December 31, 2006, the Trust participated in the drilling of 128 (117.6 net) wells, resulting in 98 (91.3 net) oil wells, 21 (18.1 net) gas wells, three (3.0 net) stratigraphic test wells and six (5.2 net) dry holes compared to prior year activities of 118 (107.3 net) wells, including 64 (60.4 net) oil wells, 41 (34.4 net) gas wells, four (4.0 net) stratigraphic test wells and nine (8.5 net) dry holes.



| | Year Ended December 31 | |
|---|---|---|
| *($ thousands)* | **2006** | 2005 |
| Land | **11,118** | 7,126 |
| Seismic | **2,202** | 4,949 |
| Drilling and completion | **97,273** | 90,180 |
| Equipment | **19,240** | 23,611 |
| Other | **2,548** | 4,626 |
| Total exploration and development | **132,381** | 130,492 |
| Property acquisitions | **1,530** | 70,986 |
| Property dispositions | **(828)** | (49,029) |
| Total capital expenditures | **133,083** | 152,449 |

In October 2005, Baytex purchased 3,500 boe/d of mainly heavy oil production at Celtic for $69 million. In December, a portion of the properties acquired with production through thermal operations was sold for $45.3 million.

*Liquidity and Capital Resources*

At December 31, 2006, total net debt (including working capital, but excluding notional mark-to-market assets and liabilities) was $366.8 million compared to $423.7 million at December 31, 2005. The decrease in total debt at year-end 2006 is primarily due to a total of $57.5 million of convertible debentures having been tendered for conversion during the year. As at December 31, 2006, $80.4 million principal amount of the original $100 million of convertible debentures have been tendered for conversion into trust units.

The Company has a credit agreement with a syndicate of chartered banks. The credit facilities consist of an operating loan and a 364-day revolving loan. Advances under the credit facilities or letters of credit can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates plus applicable margins or LIBOR rates plus applicable margins. The facilities aggregating $300 million are subject to semi-annual review and are secured by a floating charge over all of the Company's assets. At December 31, 2006 a total of $127.5 million had been drawn under the credit facilities.

The Company has US$179.7 million of 9.625 percent senior subordinated notes due July 15, 2010. These notes are unsecured and are subordinate to the Company's bank credit facilities. The Company has entered into an interest rate swap contract converting the fixed rate to a floating rate reset quarterly at the three month LIBOR rate plus 5.2 percent until the maturity of these notes.

Pursuant to various agreements with Baytex's creditors, we are restricted from making distributions to Unitholders where the distribution would or could have a material adverse effect on the Trust or its subsidiaries' ability to fulfill its obligations under Baytex's credit facilities.

The Trust believes that cash flow generated from operations, together with the existing bank facilities, will be sufficient to finance current operations, distributions to the unitholders and planned capital expenditures for the ensuing year. The timing of most of the capital expenditures is discretionary and there are no material long-term capital expenditure commitments.





*Unitholders' Equity*

The Trust is authorized to issue an unlimited number of trust units. On October 18, 2004, the Trust implemented a Distribution Reinvestment Plan ("DRIP"). Under the DRIP, Canadian unitholders are entitled to reinvest monthly cash distributions in additional trust units of the Trust. At the discretion of the Trust, these additional units may be issued at 95 percent of the "weighted average closing price" from treasury, or acquired on the market at prevailing market prices. For the purposes of the units issued from treasury, the "weighted average closing price" is calculated as the weighted average trading price of trust units for the period commencing on the second business day after the distribution record date and ending on the second business day immediately prior to the distribution payment date, such period not to exceed 20 trading days. The Trust can also acquire trust units to be issued under the DRIP at prevailing market prices.

*Non-controlling Interest*

The Company is authorized to issue an unlimited number of exchangeable shares. Exchangeable shares can be exchanged (at the option of the holder) into trust units at any time up to September 2, 2013. Up to 1.9 million exchangeable shares may be redeemed annually by the Company for either cash or the issue of trust units. At December 31, 2006, there were 1.6 million exchangeable shares outstanding. During 2006, 24,000 exchangeable shares were exchanged for trust units. The number of trust units issuable upon exchange is based upon the exchange ratio in effect at the exchange date. The exchange ratio is calculated monthly based on the cash distribution paid divided by the weighted average trust unit price of the five-day trading period ending on the record date. The exchange ratio at December 31, 2006 was 1.51072 trust units per exchangeable share (December 31, 2005 – 1.37201 trust units per exchangeable share). Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded, although they may be transferred by the holder without first being exchanged to trust units.

The exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary for them to be classified as equity. Net income has been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the balance sheet.

*Cash Distributions*

During 2006 total cash distributions of $2.16 per unit were declared. The monthly cash distribution in 2006 was increased to $0.18 from $0.15 per unit, an amount maintained since the inception of the Trust in September 2003. The 2007 monthly distribution continues at $0.18 per unit.

*Off Balance Sheet Arrangements and Contractual Obligations*

The Trust has assumed various contractual obligations and commitments, as detailed in the table below, in the normal course of operations and financing activities. These obligations and commitments have been considered when assessing the cash requirements in the above discussion of future liquidity.

*Contractual Obligations at December 31, 2006*

| *($ thousands)* | | *Payments Due* | | |
|---|---|---|---|---|
| | *Total* | *Within 1 year* | *1-3 years* | *4-5 years* |
| Long-term debt | 209,691 | – | – | 209,691 |
| Interest payable on long-term debt | 91,662 | 20,185 | 40,371 | 31,106 |
| Convertible debentures | 18,906 | – | – | 18,906 |
| Interest payable on convertible debentures | 5,100 | 1,275 | 2,550 | 1,275 |
| Operating leases | 6,891 | 1,761 | 4,398 | 732 |
| Transportation agreements | 3,177 | 2,015 | 1,130 | 32 |
| Processing obligations | 9,089 | 4,903 | 4,186 | – |
| Total contractual obligations | 344,516 | 30,139 | 52,635 | 261,742 |

Future interest payments related to our bank loan have not been included since future debt levels and interest rates are not known at this time.

The Trust also has ongoing obligations related to the abandonment and reclamation of well sites and facilities which have reached the end of their economic lives. Programs to abandon and reclaim them are undertaken regularly in accordance with applicable legislative requirements.

*Risk and Risk Management*

The exploration for and the development, production and marketing of petroleum and natural gas involves a wide range of business and financial risks, some of which are beyond the Trust's control. Included in these risks are the uncertainty of finding new reserves, the fluctuations of commodity prices, the volatile nature of interest and foreign exchange rates, and the possibility of changes to royalty, tax and environmental regulations. The petroleum industry is highly competitive and the Trust competes with a number of other entities, many of which have greater financial and operating resources.

The business risks facing the Trust are mitigated in a number of ways. Geological, geophysical, engineering, environmental and financial analyses are performed on new exploration prospects, development projects and potential acquisitions to ensure a balance between risk and reward. The Trust's ability to increase its production, revenues and cash flow depends on its success in not only developing its existing properties but also in acquiring, exploring for and developing new reserves and production and managing those assets in an efficient manner.

Despite best practice analysis being conducted on all projects, there are numerous uncertainties inherent in estimating quantities of petroleum and natural gas reserves, including future oil and natural gas prices, engineering data, projected future rates of production and the timing of future expenditures. The process of estimating petroleum and natural gas reserves requires substantial judgment, resulting in imprecise determinations, particularly for new discoveries. An independent engineering firm evaluates the Trust's properties annually to determine a fair estimate of reserves. The Reserves Committee, consisting of qualified members of the Company's Board of Directors, assists the Board in their annual review of the reserve estimates.

The provision for depletion and depreciation in the financial statements and the ceiling test are based on proved reserves estimates. Any future significant revisions could result in a full cost accounting write-down or material changes to the annual rate of depletion and depreciation.

The financial risks that the Trust is exposed to as part of the normal course of its business are managed, in part, with various financial derivative instruments, in addition to fixed-price physical delivery contracts. The use of derivative instruments is governed under formal internal policies and subject to limits established by the Board of Directors. Derivative instruments are not used for speculative or trading purposes.

The Trust's financial results can be significantly affected by the prices received for petroleum and natural gas production as commodity prices fluctuate in response to changing market forces. This pricing volatility is expected to continue. As a result, The Trust has a risk management program that may be used to protect the prices of oil and natural gas on a portion of the total expected production. The objective is to decrease exposure to market volatility and ensure the Trust's ability to finance its distributions and capital program.

The Trust's financial results are also impacted by fluctuations in the exchange rate between the Canadian dollar and the U.S. dollar. Crude oil and, to a large extent, natural gas prices are based on reference prices denominated in U.S. dollars, while the majority of expenses are denominated in Canadian dollars. The exchange rate also impacts the valuation of the U.S. dollar denominated long-term notes. The related foreign exchange gains and losses are included in net income. There is no plan at this time to fix the exchange rate on any of the Trust's long-term borrowings.



The Trust is exposed to changes in interest rates as the Company's banking facilities are based on our lenders' prime lending rate and short-term Bankers' Acceptance rates. Changes in interest rates also impact the Company's interest rate swap contract which converts the fixed interest rate of 9.625 percent on the US$179.7 million notes to a floating rate reset quarterly at the three month LIBOR rate plus 5.2 percent until the maturity of these notes.

The Trust's current position with respect to its financial derivative contracts is detailed in note 15 of the consolidated financial statements.

A summary of certain risk factors relating to our business is included in our Annual Information Form under the Risk Factors section.

## CRITICAL ACCOUNTING POLICIES

A summary of Baytex's significant accounting policies can be found in Notes 1 and 2 to the Consolidated Financial Statements. The preparation of the consolidated financial statements in accordance with generally accepted accounting principles requires management to make judgments and estimates that affect the financial results of the Trust. These critical estimates are discussed below.

*Oil and Gas Accounting*

The Trust follows the full-cost accounting guideline to account for its petroleum and natural gas operations. Under this method, all costs associated with the exploration for and development of petroleum and natural gas reserves are capitalized in one Canadian cost centre. These capitalized costs, along with estimated future development costs, are depleted and depreciated on a unit-of-production basis using estimated proved petroleum and natural gas reserves. By their inclusion in the unit-of-production calculation, reserves estimates are a significant component of the calculation of depletion and depreciation and site restoration expense.

Independent engineers engaged by the Trust use all available geological, reservoir, and production performance data to prepare the reserves estimates. These estimates are reviewed and revised, either upward or downward, as new information becomes available. Revisions are necessary due to changes in assumptions based on reservoir performance, prices, economic conditions, government restrictions and other relevant factors. If reserves estimates are revised downward, net income could be affected by increased depletion and depreciation.

*Impairment of Petroleum and Natural Gas Assets*

Companies that use the full-cost method of accounting for oil and natural gas operations are required to perform a ceiling test each quarter that calculates a limit for the net carrying cost of petroleum and natural gas assets. The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test (the "ceiling test"). The ceiling test is a two-stage process which is to be performed at least annually. The first stage of the test is a recovery test which compares the undiscounted future cash flow from proved reserves at forecast prices plus the cost less impairment of unproved properties to the net book value of the petroleum and natural gas assets to determine if the assets are impaired. An impairment loss exists when the net book value of the petroleum and natural gas assets exceeds such undiscounted cash flow. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceeds the future discounted cash flow from proved plus probable reserves at forecast prices. If reserves estimates are revised downward, net income could be affected by any additional depletion and deprecation recorded under the ceiling test calculation and could result in a significant accounting loss for a particular period.

*Goodwill*

As the result of an acquisition in 2004, goodwill of $37.8 million was recorded based on the excess of total consideration paid less the value assigned to the identifiable assets and liabilities acquired. The goodwill balance is assessed for impairment annually at year-end or more frequently if events or changes in circumstances indicate that the asset may be impaired. Impairment is charged to income in the period in which it occurs. The Trust has determined that there was no goodwill impairment as of December 31, 2006.

*Asset Retirement Obligations*

The amounts recorded for asset retirement obligations were estimated based on the Trust's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. Any changes to these estimates could change the amount recorded for asset retirement obligations and may materially impact the consolidated financial statements of future periods.

*Future Income Taxes*

The Trust is a unit trust for income tax purposes, and is taxable on income not allocated to the unitholders. From inception on September 2, 2003, the Trust has allocated all of its taxable income to the unitholders and, accordingly, no provision for income taxes is required at the Trust level.

The Company is subject to corporate income taxes and follows the liability method of accounting for income taxes. Under this method, future income taxes are recorded for the effect of any difference between the accounting and income tax basis of an asset or liability, using substantially enacted income tax rates. Future tax balances are adjusted for any changes in the tax rate and the adjustment is recognized in income in the period that the rate change occurs.

*Unit-based Compensation*

The Trust Unit Rights Incentive Plan is described in note 10 to the Consolidated Financial Statements. The exercise price of the rights granted under the Plan may be reduced in future periods in accordance with the terms of the Plan. The Trust uses the binomial-lattice model to calculate the estimated fair value of the outstanding rights.

Compensation expense associated with rights granted under the plan is recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. The exercise of trust unit rights are recorded as an increase in trust units with a corresponding reduction in contributed surplus.

## NEW ACCOUNTING PRONOUNCEMENTS

*Financial Instruments*

Instruments Effective January 1, 2007, the Trust will be required to adopt the Canadian Institute of Chartered Accountants ("CICA") Section 1530 "Comprehensive Income", Section 3251 "Equity", and Section 3855 "Financial Instruments – Recognition and Measurement". It is also the Trust's intention to early adopt Section 3862 "Financial Instruments – disclosure" and Section 3863 "Financial Instruments – presentation" in place of Section 3861 "Financial Instruments – disclosure and presentation". Under the new standards a new financial statement, Consolidated Statement of Other Comprehensive Income, has been introduced that will provide for certain gains and losses, such as changes in fair value of hedging instruments, to be temporarily recorded outside the income statement. All financial instruments including derivatives, are to be included on a company's balance sheet and measured, either at their fair values or, in limited circumstances when fair value may not be considered most relevant, at cost or amortized costs. The standards also provide guidance on when gains and losses as a result of changes in fair values are to be recognized in the income statement. In addition, the requirements for hedge accounting have been clarified under the new standards. The Company is assessing the impact on its Consolidated Financial Statements.

A new location for recognizing certain gains and losses – other comprehensive income – has been introduced with the issuance of Section 1530, "Comprehensive Income". An integral part of the accounting standards on recognition and measurement of financial instruments is the ability to present certain gains and losses outside net income, in other Comprehensive Income. This standard requires that a company should present comprehensive income and its components in a financial statement displayed with the same prominence as other financial statements that constitute a complete set of financial statements, in both annual and interim financial statements. Exchange gains and losses arising from the translation of the financial statements of a self-sustaining foreign operation, previously recognized in a separate component of shareholders' equity, in accordance with Section 1650, "Foreign Currency Translation", will now be recognized in a separate component of other comprehensive income.

These three new Handbook Sections are effective date for annual and interim periods in fiscal years beginning on or after October 1, 2006. The Trust is evaluating the impact the adoption of these new standards will have on its consolidated financial statements.

*Capital Disclosures*

In December 2006, the CICA issued Section 1535 "Capital Disclosures". Under the new standard, which is effective for fiscal years beginning on or after October 1, 2007, an entity is required to provide additional disclosure about its objectives, policies and process for managing capital. The Trust does not expect application of this new standard to have a material impact on its consolidated financial statements.

*Accounting Changes*

Effective January 1, 2007, the Trust will be required to adopt the CICA Section 1506 "Accounting Changes". The new standard provides clarification on the criteria for changes in accounting policies as well as the accounting treatment and disclosure of changes in accounting policies, changes in estimates and corrections of errors. The application of this new standard will not have a material impact on the Trust's consolidated financial statements.

## FOURTH QUARTER 2006

The following discussion reviews the Trust's results of operations for the fourth quarter of 2006.

*Production*

Light oil and NGL production for the fourth quarter of 2006 decreased by nine percent to 3,643 bbl/d from 4,022 bbl/d a year earlier. Heavy oil production decreased seven percent to 22,416 bbl/d for the fourth quarter of 2006 compared to 24,051 bbl/d a year ago. Natural gas production decreased by 13 percent to 51.4 MMcf/d for the fourth quarter of 2005 compared to 58.9 MMcf/d for the same period last year. The decrease in light oil, NGL and natural gas volumes was largely due to delayed timing of certain natural gas tie-ins and natural decline. The decrease in heavy oil production is attributable to the sale of approximately 2,100 bbl/d of SAGD production at year-end 2005.

*Revenue*



Petroleum and natural gas sales decreased 17 percent to $134.5 million for the fourth quarter of 2006 from $162.4 million for the same period in 2005. Revenue from light oil and NGL for the fourth quarter of 2006 decreased 21 percent from the same period a year ago due to a nine percent decrease in production and a 13 percent decrease in wellhead prices. Revenue from heavy oil increased one percent due to a nine percent increase in wellhead prices offset by a seven percent decrease in production. Revenue from natural gas decreased 43 percent as the result of a 34 percent decrease in wellhead prices and a 13 percent decrease in production. Total royalties decreased to $18.5 million for the fourth quarter of 2006 from $27.3 million in 2005. This decrease is reflective of the decrease in total revenue.

*Royalties*

Total royalties for the fourth quarter of 2006 were 13.8 percent of sales compared to 16.8 percent of sales for the same period in 2005. For the fourth quarter of 2006, royalties were 14.7 percent of sales for light oil and NGL, 12.1 percent for heavy oil and 17.5 percent for natural gas. These rates compared to 16.2 percent, 11.7 percent and 24.3 percent, respectively, for the same period last year.

*Operating Expenses*

Operating expenses for the fourth quarter of 2006 decreased to $29.8 million from $33.3 million in the corresponding quarter last year. Operating expenses were $9.36 per boe for the fourth quarter of 2006 compared to $9.55 per boe for the fourth quarter of 2005. For the fourth quarter of 2006, operating expenses were $12.25 per bbl of light oil and NGL, $9.47 per bbl of heavy oil and $1.31 per Mcf of natural gas. The operating expenses for the same period a year ago were $6.28, $11.00 and $1.22, respectively.

*Transportation Expenses*

Transportation expenses for the fourth quarter of 2006 were $6.4 million compared to $6.0 million for the fourth quarter of 2005. These expenses were $2.00 per boe for the fourth quarter of 2006 compared to $1.71 for the same period in 2005. Transportation expenses were $2.41 per bbl of oil and $0.12 per Mcf of natural gas. The corresponding amounts for 2005 were $2.02 and $0.14, respectively.

*General and Administrative Expenses*

General and administrative expenses for the fourth quarter of 2005 increased to $5.9 million from $4.6 million in 2005. On a per sales unit basis, these expenses were $1.84 per boe for the fourth quarter of 2006 compared to $1.32 per boe for the same period in 2005. The increased costs are due to escalating costs in the labour market, additional expenses associated with the New York Stock Exchange listing and costs relating to compliance requirements under the Sarbanes-Oxley Act. In accordance with our full cost accounting policy, no expenses were capitalized in either the fourth quarter of 2006 or 2005.

*Unit Based Compensation Expense*

Compensation expense related to the Trust's unit rights incentive plan was $2.2 million for the fourth quarter of 2006 compared to $1.8 million for the fourth quarter of 2005.

*Interest Expense*

Interest expense decreased to $8.8 million for the fourth quarter of 2006 from $9.7 million for the same quarter last year, primarily due to the decreased outstanding balance in convertible debentures and the lower foreign exchange conversion rates.

*Foreign Exchange*

Foreign exchange in the fourth quarter of 2006 was a loss of $9.0 million compared to a loss of $0.9 million in the prior year. The loss is based on the translation of the U.S. dollar denominated long-term debt at 0.8581 at December 31, 2006 compared to 0.8966 at September 30, 2006. The 2005 gain is based on translation at 0.8577 at December 31, 2005 compared to 0.8613 at September 30, 2005.

*Depletion, Depreciation and Accretion*

The provision for depletion, depreciation and accretion at $39.5 million for the fourth quarter of 2006 decreased from $41.6 million from the same quarter in 2005. This decrease is due to lower production. On a sales-unit basis, the provision for the current quarter was $12.38 per boe compared to $11.91 per boe for the same quarter in 2005.

*Net Income*

Net income for the fourth quarter of 2006 was $20.0 million compared to $35.2 million for the fourth quarter in 2005. The variance was the result of lower production, lower sales prices, and losses due to foreign exchange which was partially offset by a recovery of future income tax.

## TRUST UNIT INFORMATION

At February 28, 2007, the Trust had 75,646,323 units outstanding and the Company had 1,572,153 exchangeable shares outstanding. The exchange ratio at February 28, 2007 was 1.53664 trust units per exchangeable share.

At February 28, 2007, the Trust had $18.5 million convertible unsecured subordinated debentures outstanding which are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $14.75 per unit.

## SELECTED ANNUAL INFORMATION

*Financial*

| *($ thousands, except per unit amounts)* | **2006** | 2005 | 2004 |
|---|---|---|---|
| Revenue | **556,689** | 546,940 | 420,400 |
| Net income (1) | **147,069** | 79,876 | 16,764 |
| Per unit basic (1) | **2.02** | 1.19 | 0.27 |
| Per unit diluted (1) | **1.91** | 1.15 | 0.26 |
| Total assets | **1,079,629** | 1,105,567 | 1,104,136 |
| Total long-term financial liabilities | **228,597** | 283,565 | 216,583 |
| Cash distributions declared per unit | **2.16** | 1.80 | 1.80 |

*(1) Net income and net income per unit is after non-controlling interest related to exchangeable shares.*

Overall production for 2006 was 34,292 boe per day which represented a three percent decrease from 35,177 boe per day in 2005. Average wellhead prices received during 2006 were $44.48 per boe compared to $42.60 during 2005. Production in 2004 was 34,022 boe per day. Average wellhead prices received in 2004 were $33.75 per boe.

## QUARTERLY INFORMATION

| ($ thousands, except per unit amounts) | 2006 Q4 | 2006 Q3 | 2006 Q2 | 2006 Q1 | 2005 Q4 | 2005 Q3 | 2005 Q2 | 2005 Q1 |
|---|---|---|---|---|---|---|---|---|
| Revenue | 134,541 | 145,754 | 140,163 | 136,231 | 162,356 | 154,930 | 118,379 | 111,275 |
| Cash distributions declared per unit | 0.54 | 0.54 | 0.54 | 0.54 | 0.45 | 0.45 | 0.45 | 0.45 |

*Reconciliation of Net Income to Cash Flow from Operations*

*Financial*

| ($ thousands, except per unit amounts) | 2006 Q4 | 2006 Q3 | 2006 Q2 | 2006 Q1 | 2005 Q4 | 2005 Q3 | 2005 Q2 | 2005 Q1 |
|---|---|---|---|---|---|---|---|---|
| Net income (loss) (1) | 19,988 | 42,040 | 56,162 | 28,879 | 35,184 | 39,524 | 16,779 | (11,611) |
| Items not affecting cash: | | | | | | | | |
| Unit based compensation | 2,168 | 1,740 | 1,821 | 1,731 | 1,809 | 1,197 | 1,048 | 1,292 |
| Amortization of deferred charges | 304 | 314 | 200 | 449 | 459 | 459 | 314 | 261 |
| Unrealized foreign exchange loss (gain) | 8,997 | 54 | (9,375) | 216 | 864 | (11,607) | 2,879 | 1,080 |
| Depletion, depreciation and accretion | 39,488 | 38,285 | 36,639 | 38,167 | 41,587 | 40,772 | 41,497 | 43,279 |
| Accretion on debentures | 33 | 42 | 31 | 83 | 120 | 155 | 46 | – |
| Unrealized loss (gain) on financial derivatives | 408 | (11,762) | 7,527 | 6,617 | (26,409) | (9,535) | (11,066) | 32,313 |
| Future income taxes (recovery) | (10,167) | 332 | (24,742) | (6,592) | 11,088 | 5,602 | (2,007) | (21,757) |
| Non-controlling interest | 2,300 | 885 | 1,202 | 198 | 785 | 934 | 447 | (317) |
| Cash flow from operations (2) | 63,519 | 71,930 | 69,465 | 69,748 | 65,487 | 67,501 | 49,937 | 44,540 |
| Change in non-cash working capital | (1,913) | 7,608 | (15,667) | 914 | 3,393 | (6,392) | (208) | (17,005) |
| Asset retirement expenditures | (233) | (361) | (746) | (407) | (382) | (233) | (50) | (972) |
| Decrease in deferred charges and other assets | (409) | (488) | (489) | (489) | (1,134) | 401 | 228 | (472) |
| Cash flow from operating activities | 60,964 | 78,689 | 52,563 | 69,766 | 67,364 | 61,277 | 49,907 | 26,091 |
| Net income (loss) (1) per unit | | | | | | | | |
| Basic | 0.27 | 0.57 | 0.77 | 0.41 | 0.51 | 0.59 | 0.25 | (0.17) |
| Diluted | 0.26 | 0.54 | 0.73 | 0.39 | 0.47 | 0.54 | 0.25 | (0.17) |
| Cash flow from operations (2) per unit | | | | | | | | |
| Basic | 0.85 | 0.98 | 0.96 | 0.99 | 0.95 | 1.00 | 0.75 | 0.67 |
| Diluted | 0.79 | 0.90 | 0.88 | 0.90 | 0.86 | 0.89 | 0.71 | 0.64 |
| Cash flow from operating activities per unit | | | | | | | | |
| Basic | 0.81 | 1.07 | 0.72 | 0.99 | 0.95 | 0.91 | 0.75 | 0.39 |
| Diluted | 0.78 | 0.98 | 0.66 | 0.90 | 0.84 | 0.80 | 0.69 | 0.37 |

*(1) Net income and net income per unit is after non-controlling interest related to exchangeable shares.*

*(2) The Trust evaluates performance based on net income and cash flow from operations. Cash flow from operations and cash flow per unit are not measurements based on generally accepted accounting principles ("GAAP"), but are financial terms commonly used in the oil and gas industry. Cash flow represents cash generated from operating activities before changes in non-cash working capital, deferred charges and other assets and deferred credits. The Trust's determination of cash flow may not be comparable with the calculation of similar measures for other entities. The Trust considers it a key measure of performance as it demonstrates the ability of the Trust to generate the cash flow necessary to fund future distributions to unitholders and capital investments.*

| *Production* | 2006 | | | | 2005 | | | |
|---|---|---|---|---|---|---|---|---|
| | Q4 | Q3 | Q2 | Q1 | Q4 | Q3 | Q2 | Q1 |
| Light oil and NGL *(bbl/d)* | 3,643 | 3,594 | 3,619 | 4,089 | 4,022 | 4,063 | 3,404 | 3,876 |
| Heavy oil *(bbl/d)* | 22,416 | 21,325 | 20,413 | 21,134 | 24,051 | 20,061 | 19,653 | 21,279 |
| Total oil and NGL *(bbl/d)* | 26,059 | 24,919 | 24,032 | 25,223 | 28,073 | 24,124 | 23,058 | 25,155 |
| Natural gas *(MMcf/d)* | 51.4 | 54.9 | 54.7 | 60.6 | 58.9 | 63.9 | 59.3 | 59.5 |
| Oil equivalent *(boe/d)* | 34,631 | 34,074 | 33,154 | 35,319 | 37,895 | 34,780 | 32,937 | 35,068 |
| *Average Prices* | | | | | | | | |
| WTI oil *(US$/bbl)* | 60.21 | 70.48 | 70.70 | 63.48 | 60.02 | 63.19 | 53.17 | 49.84 |
| Edmonton par oil *($/bbl)* | 64.49 | 79.17 | 78.61 | 68.99 | 71.18 | 76.51 | 65.76 | 61.44 |
| BTE light oil *($/bbl)* | 48.62 | 57.94 | 57.83 | 51.33 | 55.78 | 59.24 | 53.06 | 46.69 |
| BTE heavy oil *($/bbl)* | 41.15 | 48.28 | 47.10 | 37.87 | 37.75 | 45.39 | 35.71 | 30.83 |
| BTE total oil *($/bbl)* | 42.19 | 49.68 | 48.71 | 40.05 | 40.33 | 47.74 | 38.27 | 33.27 |
| BTE natural gas *($/Mcf)* | 7.03 | 6.35 | 6.68 | 8.36 | 10.69 | 8.39 | 7.08 | 6.69 |
| BTE oil equivalent *($/boe)* | 42.19 | 46.57 | 46.35 | 42.94 | 46.48 | 48.54 | 39.53 | 35.21 |

## 2007 GUIDANCE

Baytex has set a 2007 capital budget of $140 million designed to maintain our production at the same level as 2006, which is expected to average approximately 34,400 boe/d. Sixty percent of this budget has been allocated to our heavy oil operations, with the planned drilling of 78 gross wells including 18 primary horizontal producers in our Seal area in the Peace River oil sands region. Forty percent of this budget has been allocated to our conventional oil and gas operations, with the planned drilling of 41 gross wells. Approximately 35 to 40 percent of the $140 million capital budget for the year is being incurred in the first quarter, including the drilling of nine horizontal production wells and four stratigraphic test wells at Seal.

Based on the current outlook of commodity prices, cash flow from operations in 2007 is expected to be sufficient to essentially fund the above capital budget and the $0.18 per unit monthly distributions to our unitholders. Baytex will continue to have a strong balance sheet, with total debt of approximately $365 million and over 50 percent of our $300 million secured bank facilities undrawn.

Baytex has entered into the following contracts to provide downside protection to 2007 cash flow while allowing for participation in a high commodity price environment. Baytex will continue to monitor market developments and may enter into additional similar contracts if deemed desirable.

*Financial Derivative Contracts*

*OIL*

| | *Period* | *Volume* | *Price* | *Index* |
|---|---|---|---|---|
| Price collar | Calendar 2007 | 2,000 bbl/d | US$55.00 – $83.60 | WTI |
| Price collar | Calendar 2007 | 3,000 bbl/d | US$55.00 – $83.75 | WTI |
| Price collar | Calendar 2007 | 2,000 bbl/d | US$60.00 – $80.40 | WTI |
| Price collar | Calendar 2007 | 1,000 bbl/d | US$60.00 – $80.60 | WTI |

*FOREIGN CURRENCY*

| | *Period* | *Amount* | *Floor* | *Cap* |
|---|---|---|---|---|
| Collar | Calendar 2007 | $5,000,000 per month | Cdn/US$1.0835 | Cdn/US$1.1600 |

*INTEREST RATE*

| | *Period* | *Principal* | *Rate* |
|---|---|---|---|
| Swap | November 2003 to July 2010 | US$179,699,000 | 3-month LIBOR plus 5.2% |

*Physical Sale Contracts*

*GAS*

| | *Period* | *Volume* | *Price* |
|---|---|---|---|
| Price collar | November 1, 2006 to March 31, 2007 | 5,000 GJ/d | $8.00 – $9.45 |
| Price collar | November 1, 2006 to March 31, 2007 | 5,000 GJ/d | $8.00 – $9.50 |
| Price collar | November 1, 2006 to March 31, 2007 | 5,000 GJ/d | $8.00 – $10.15 |
| Price collar | April 1, 2007 to October 31, 2007 | 5,000 GJ/d | $6.65 – $9.15 |
| Price collar | April 1, 2007 to October 31, 2007 | 5,000 GJ/d | $6.65 – $9.30 |
| Price collar | April 1, 2007 to October 31, 2007 | 2,500 GJ/d | $6.65 – $8.25 |
| Price collar | April 1, 2007 to October 31, 2007 | 2,000 GJ/d | $6.65 – $8.30 |
| Price collar | April 1, 2007 to October 31, 2007 | 2,500 GJ/d | $6.65 – $8.73 |

The Trust is exposed to credit-related losses in the event of non-performance by counter-parties to these contracts. See note 15 to the December 31, 2006 consolidated financial statements for description of accounting treatment of these derivative contracts.

*Evaluation of Disclosure Controls and Procedures*

Raymond Chan, the President and Chief Executive Officer, and Derek Aylesworth, the Chief Financial Officer of Baytex (together the "Disclosure Officers"), are responsible for establishing and maintaining disclosure controls and procedures for Baytex. For the year ended December 31, 2006, the Disclosure Officers evaluated the effectiveness of the disclosure controls and procedures. As a result of this evaluation, the Disclosure Officers have concluded that the disclosure controls and procedures are effective to provide reasonable assurance that all material or potentially material information about the activities of the Trust is made known to them by others within Baytex.

It should be noted that while our Disclosures Officers believe that Baytex's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls and procedures or internal controls over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

There were no changes in our internal control over financial reporting during the quarter ended December 31, 2006 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

## ADDITIONAL INFORMATION

Additional information relating to the Trust, including the Annual Information Form, may be found on SEDAR at www.sedar.com.

# MANAGEMENT'S REPORT

Management, in accordance with Canadian generally accepted accounting principles, has prepared the accompanying consolidated financial statements of Baytex Energy Trust. Financial and operating information presented throughout this Annual Report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

Deloitte & Touche LLP were appointed by the Trust's unitholders to express an audit opinion on the consolidated financial statements. Their examination included such tests and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are presented fairly in accordance with Canadian generally accepted accounting principles.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board exercises this responsibility through the Audit Committee, with assistance from the Reserves Committee regarding the annual review of our petroleum and natural gas reserves. The Audit Committee meets regularly with management and the independent registered chartered accountants to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit Committee also considers the independence of the external auditors and reviews their fees. The external auditors have access to the Audit Committee without the presence of management.

Raymond T. Chan, CA
*President and Chief Executive Officer*
*Baytex Energy Ltd.*

W. Derek Aylesworth, CA
*Chief Financial Officer*
*Baytex Energy Ltd.*

*March 16, 2007*

To the Unitholders of Baytex Energy Trust

We have audited the consolidated balance sheets of Baytex Energy Trust (the "Trust") as at December 31, 2006 and 2005 and the consolidated statements of operations and accumulated income (deficit) and cash flows for the years then ended. These financial statements are the responsibility of the management of the Trust. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

On March 16, 2007, we reported separately to the Board of Directors and the Unitholders of Baytex Energy Trust on our audit, conducted in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States) on the consolidated financial statements for the same period, prepared in accordance with Canadian generally accepted accounting principles but which included Note 17, Differences Between Canadian and United States Generally Accepted Accounting Principles.

Deloitte & Touche LLP

*Calgary, Alberta*
*March 16, 2007*

Deloitte & Touche LLP
*Chartered Accountants*

# CONSOLIDATED BALANCE SHEETS

| *As at December 31 (thousands)* | 2006 | 2005 |
|---|---|---|
| **ASSETS** | | |
| Current assets | | |
| Accounts receivable | $ 64,716 | $ 73,869 |
| Crude oil inventory | 9,609 | 9,984 |
| Financial derivative contracts *(note 15)* | 3,448 | 5,183 |
| | 77,773 | 89,036 |
| Deferred charges and other assets | 4,475 | 9,038 |
| Petroleum and natural gas properties *(note 3)* | 959,626 | 969,738 |
| Goodwill | 37,755 | 37,755 |
| | $ 1,079,629 | $ 1,105,567 |
| **LIABILITIES** | | |
| Current liabilities | | |
| Accounts payable and accrued liabilities | $ 71,521 | $ 89,966 |
| Distributions payable to unitholders | 13,522 | 10,393 |
| Bank loan *(note 4)* | 127,495 | 123,588 |
| Financial derivative contracts *(note 15)* | 1,055 | – |
| | 213,593 | 223,947 |
| Long-term debt *(note 5)* | 209,691 | 209,799 |
| Convertible debentures *(note 6)* | 18,906 | 73,766 |
| Asset retirement obligations *(note 7)* | 39,855 | 33,010 |
| Deferred obligations *(note 16)* | 2,391 | 4,558 |
| Future income taxes *(note 12)* | 118,858 | 159,745 |
| | 603,294 | 704,825 |
| Non-controlling interest *(note 9)* | 17,187 | 12,810 |
| **UNITHOLDERS' EQUITY** | | |
| Unitholders' capital *(note 8)* | 637,156 | 555,020 |
| Conversion feature of debentures *(note 6)* | 940 | 3,698 |
| Contributed surplus | 13,357 | 10,332 |
| Deficit | (192,305) | (181,118) |
| | 459,148 | 387,932 |
| | $ 1,079,629 | $ 1,105,567 |

Commitments and contingencies *(note 16)*

*See accompanying notes to the consolidated financial statements.*

On behalf of the Board

Naveen Dargan
*Director, Baytex Energy Ltd.*

W. A. Blake Cassidy
*Director, Baytex Energy Ltd.*

| *Years ended December 31 (thousands, except per unit data)* | 2006 | 2005 |
|---|---|---|
| Revenue | | |
| Petroleum and natural gas sales | $ 556,689 | $ 546,940 |
| Royalties | (85,043) | (81,898) |
| Realized gain (loss) on financial derivatives | 2,529 | (48,462) |
| Unrealized gain (loss) on financial derivatives | (2,790) | 14,696 |
| | 471,385 | 431,276 |
| Expenses | | |
| Operating | 112,406 | 110,648 |
| Transportation | 24,346 | 22,399 |
| General and administrative | 20,843 | 16,010 |
| Unit based compensation *(note 10)* | 7,460 | 5,346 |
| Interest *(note 5)* | 34,960 | 33,124 |
| Foreign exchange gain | (108) | (6,784) |
| Depletion, depreciation and accretion | 152,579 | 167,135 |
| | 352,486 | 347,878 |
| Income before income taxes and non-controlling interest | 118,899 | 83,398 |
| Income taxes (recovery) *(note 12)* | | |
| Current | 8,414 | 8,747 |
| Future | (41,169) | (7,074) |
| | (32,755) | 1,673 |
| Income before non-controlling interest | 151,654 | 81,725 |
| Non-controlling interest *(note 9)* | (4,585) | (1,849) |
| Net income | 147,069 | 79,876 |
| Deficit, beginning of year | (181,118) | (139,453) |
| Distributions to unitholders | (158,256) | (121,541) |
| Deficit, end of year | $ (192,305) | $ (181,118) |
| Net income per trust unit *(note 11)* | | |
| Basic | $ 2.02 | $ 1.19 |
| Diluted | $ 1.91 | $ 1.15 |

*See accompanying notes to the consolidated financial statements.*

# CONSOLIDATED STATEMENTS OF CASH FLOWS

| *Years ended December 31 (thousands)* | 2006 | 2005 |
|---|---|---|
| CASH PROVIDED BY (USED IN): | | |
| Operating activities | | |
| Net income | $ 147,069 | $ 79,876 |
| Items not affecting cash: | | |
| Unit based compensation *(note 10)* | 7,460 | 5,346 |
| Amortization of deferred charges | 1,267 | 1,492 |
| Unrealized foreign exchange gain | (108) | (6,784) |
| Depletion, depreciation, and accretion | 152,579 | 167,135 |
| Accretion on debentures *(note 6)* | 189 | 321 |
| Unrealized loss (gain) on financial derivatives *(note 15)* | 2,790 | (14,696) |
| Future income tax recovery | (41,169) | (7,074) |
| Non-controlling interest *(note 9)* | 4,585 | 1,849 |
| | 274,662 | 227,465 |
| Change in non-cash working capital *(note 13)* | (9,058) | (20,212) |
| Asset retirement expenditures | (1,747) | (1,637) |
| Decrease in deferred charges and other assets | (1,875) | (977) |
| Cash flow from operating activities | 261,982 | 204,639 |
| Financing activities | | |
| Increase (decrease) in bank loan | 3,907 | (37,856) |
| Issue of trust units *(note 8)* | 8,509 | 2,916 |
| Payments of distributions | (141,453) | (114,221) |
| Issuance of convertible debentures *(note 6)* | – | 100,000 |
| Convertible debentures issue costs *(note 6)* | – | (4,250) |
| Cash flow from financing activities | (129,037) | (53,411) |
| Investing activities | | |
| Petroleum and natural gas property expenditures | (133,911) | (201,478) |
| Proceeds on disposal of petroleum and natural gas properties | 828 | 49,029 |
| Change in non-cash working capital *(note 13)* | 138 | 1,221 |
| Cash flow from investing activities | (132,945) | (151,228) |
| Change in cash and cash equivalents during the year | – | – |
| Cash and cash equivalents, beginning of year | – | – |
| Cash and cash equivalents, end of year | $ – | $ – |

*See accompanying notes to the consolidated financial statements.*

## 1. BASIS OF PRESENTATION

Baytex Energy Trust (the "Trust") was established on September 2, 2003 under a Plan of Arrangement involving the Trust and Baytex Energy Ltd. (the "Company"). The Trust is an open-ended investment trust created pursuant to a trust indenture. Subsequent to the Plan of Arrangement, the Company is a subsidiary of the Trust.

The consolidated financial statements include the accounts of the Trust and its subsidiaries and have been prepared by management in accordance with Canadian generally accepted accounting principles ("GAAP") as described in note 2.

## 2. SIGNIFICANT ACCOUNTING POLICIES

### Consolidation

The consolidated financial statements include the accounts of the Trust and its wholly owned subsidiaries from the respective dates of acquisition of the subsidiary companies. Inter-company transactions and balances are eliminated upon consolidation. Investments in unincorporated joint ventures are accounted for using the proportionate consolidation method as described under the "Joint Interests" heading.

### Measurement Uncertainty

The preparation of the consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and revenue and expenses during the reporting period. Actual results can differ from those estimates.

In particular, amounts recorded for depreciation and depletion and amounts used for ceiling test calculations are based on estimates of petroleum and natural gas reserves and future costs required to develop those reserves. The Trust's reserves estimates are evaluated annually by an independent engineering firm. By their nature, these estimates of reserves and the related future cash flows are subject to measurement uncertainty, and the impact on the consolidated financial statements of future periods could be material.

The amounts recorded for asset retirement obligations were estimated based on the Trust's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. Any changes to these estimates could change the amount recorded for asset retirement obligations and may materially impact the consolidated financial statements of future periods.

Cash and Cash Equivalents

Cash and cash equivalents include monies on deposit and short-term investments, accounted for at cost, which have an initial maturity date of not more that 90 days.

Crude Oil Inventory

Crude oil inventory, consisting of production in transit in pipelines at the balance sheet date pursuant to a long-term crude oil supply agreement, is valued at the lower of cost using the weighted average method or net realizable value.

Petroleum and Natural Gas Operations

The Trust follows the full cost method of accounting for its petroleum and natural gas operations whereby all costs relating to the exploration for and development of petroleum and natural gas reserves are capitalized in one Canadian cost centre and charged against income, as set out below. Such costs include land acquisition, drilling of productive and non-productive wells, geological and geophysical, production facilities, carrying costs directly related to unproved properties and corporate expenses directly related to acquisition, exploration and development activities and do not include any costs related to production or general overhead expenses. These costs along with estimated future capital costs that are based on current costs and that are incurred in developing proved reserves are depleted and depreciated on a unit of production basis using estimated proved petroleum and natural gas reserves, with both production and reserves stated before royalties. For purposes of this calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of gas equates to one barrel of oil. Costs of acquiring and evaluating unproved properties are excluded from costs subject to depletion and depreciation until it is determined whether proved reserves are attributable to the properties or impairment occurs. Unproved properties are evaluated for impairment on an annual basis.

Gains or losses on the disposition of petroleum and natural gas properties are recognized only when crediting the proceeds to costs would result in a change of 20 percent or more in the depletion rate.

The net amount at which petroleum and natural gas properties are carried is subject to a cost recovery test (the "ceiling test"). The ceiling test is a two-stage process which is to be performed at least annually. The first stage of the test is a recovery test which compares the undiscounted future cash flow from proved reserves at forecast prices plus the cost less impairment of unproved properties to the net book value of the petroleum and natural gas assets to determine if the assets are impaired. An impairment loss exists when the net book value of the petroleum and natural gas assets exceeds such undiscounted cash flow. The second stage determines the amount of the impairment loss to be recorded. The impairment is measured as the amount by which the net book value of the petroleum and natural gas assets exceeds the future discounted cash flow from proved plus probable reserves at forecast prices. Any impairment is recorded as additional depletion and depreciation.

Goodwill

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the fair value for accounting purposes of the net identifiable assets and liabilities of the acquired business. Goodwill is stated at cost less impairment and is not amortized. The goodwill balance is assessed for impairment annually at year-end or more frequently if events or changes in circumstances indicate that the asset may be impaired. The test for impairment is conducted by the comparison of the net book value to the fair value of the reporting entity. If the

fair value of the Trust is less than the net book value, impairment is deemed to have occurred. The extent of the impairment is measured by allocating the fair value of the Trust to the identifiable assets and liabilities at their fair values. Any remainder of this allocation is the implied value of goodwill. Any excess of the net book value of goodwill over this implied value is the impairment amount. Impairment is charged to income in the period in which it occurs.

### Convertible Unsecured Subordinated Debentures

The debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders' equity. Issue costs will be amortized over the term of the debentures, and the debt portion will accrete up to the principal balance at maturity. The accretion, amortization of issue costs and the interest paid are expensed as interest expense in the consolidated statements of operations. If the debentures are converted to trust units, a portion of the value of the conversion feature under unitholders' equity will be reclassified to unitholders' capital along with the principal amounts converted.

### Asset Retirement Obligation

The Trust recognizes a liability at discounted fair value for the future abandonment and reclamation costs associated with the petroleum and natural gas properties. The fair value of the liability is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until the date of expected settlement of the retirement obligations. The related accretion expense is recognized in the statement of operations. The provision will be revised for the effect of any changes to timing related to cash flow or undiscounted abandonment costs. Actual expenditures incurred for the purpose of site reclamation are charged to the asset retirement obligations to the extent that the liability exists on the balance sheet. Differences between the actual costs incurred and the fair value of the liability recorded are recognized in income in the period the actual costs are incurred.

### Joint Interests

A portion of the Trust's exploration, development and production activities is conducted jointly with others. These consolidated financial statements reflect only the Trust's proportionate interest in such activities.

### Foreign Currency Translation

Foreign currency denominated monetary items are translated into Canadian dollars at the exchange rate in effect at the balance sheet date. Exchange gains and losses on long-term monetary items that do not qualify for hedge accounting are recognized in income.

Revenue and expenses are translated at the monthly average rate of exchange. Translation gains and losses are included in net income.

### Deferred Charges and Other Assets

Costs related to the exchange of the senior subordinated notes, issuance of the convertible debenture and procurement of the long-term supply contract have been deferred and are amortized over the term of the instruments on a straight-line basis.

### Revenue Recognition

Revenue associated with sales of crude oil, natural gas and natural gas liquids is recognized when title passes to the purchaser, normally at the pipeline delivery point for natural gas and at the wellhead for crude oil, except products sold pursuant to the long-term crude oil supply contract where title transfer is at the refinery gate.

### Financial Derivative Contracts

The Trust formally documents its risk management objectives and strategies to manage exposures to fluctuations in commodity prices, interest rates and foreign currency exchange rates. The risk management policies include the permitted use of derivative financial instruments, including swaps and collars, used to manage these fluctuations. All transactions of this nature entered into by the Trust are related to an underlying financial instrument or to future petroleum and natural gas production. The Trust does not use financial derivatives for trading or speculative purposes. Financial derivative contracts used as hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective in order to continue accrual accounting for positions hedged with financial derivative contracts. Financial derivative contracts that do not qualify for hedge accounting are recognized in the balance sheet and measured at fair value, with changes in fair value reported separately in the statement of operations as income or expense.

### Future Income Taxes

The Trust is a unit trust for income tax purposes, and is taxable on taxable income not allocated to the unitholders. From inception on September 2, 2003, the Trust has allocated all of its taxable income to the unitholders, and accordingly, no provision for income taxes is required at the Trust level.

The Company is subject to corporate income taxes and follows the liability method of accounting for income taxes. Under this method, future income taxes are recorded for the effect of any difference between the accounting and income tax basis of an asset or liability, using substantially enacted income tax rates. Future tax balances are adjusted for any changes in the tax rate and the adjustment is recognized in income in the period that the rate change occurs.

### Unit-based Compensation

The Trust Unit Rights Incentive Plan is described in note 10. The exercise price of the rights granted under the Plan may be reduced in future periods in accordance with the terms of the Plan. The Trust uses the binomial-lattice model to calculate the estimated fair value of the outstanding rights.

Compensation expense associated with rights granted under the plan is recognized in income over the vesting period of the plan with a corresponding increase in contributed surplus. The exercise of trust unit rights are recorded as an increase in trust units with a corresponding reduction in contributed surplus.

### Non-controlling Interest

The exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary in order for them to be classified as equity. Net income has been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the consolidated balance sheet. As the exchangeable shares are converted to trust units, the exchange is accounted for as a step-acquisition where unitholders' capital is increased by the fair value of the trust units issued. The difference between the fair value of the trust units issued and the book value of the exchangeable shares is recorded as an increase in petroleum and natural gas properties.

### Per-unit Amounts

Basic net income per unit is computed by dividing net income by the weighted average number of trust units outstanding during the year. Diluted per unit amounts reflect the potential dilution that could occur if trust unit rights were exercised, exchangeable shares were exchanged, or convertible debentures were converted. The treasury stock method is used to determine the dilutive effect of trust unit rights, whereby any proceeds from the exercise of trust unit rights or other dilutive instruments and the amount of compensation expense, if any, attributed to future services and not yet recognized are assumed to be used to purchase trust units at the average market price during 2006.

## 3. PETROLEUM AND NATURAL GAS PROPERTIES

| *As at December 31* | 2006 | 2005 |
|---|---|---|
| Petroleum and natural gas properties | $ 2,600,834 | $ 2,461,045 |
| Accumulated depletion and depreciation | (1,641,208) | (1,491,307) |
| | $ 959,626 | $ 969,738 |

In calculating the depletion and depreciation provision for 2006, $34.3 million (2005 – $46.6 million) of costs relating to undeveloped properties were excluded from costs subject to depletion and depreciation. No general and administrative expenses have been capitalized since the inception of operations as a trust effective September 2, 2003.

The net book value of petroleum and natural gas properties are subject to a ceiling test, which was calculated at December 31, 2006 using the following benchmark reference prices for the years 2007 to 2011 adjusted for commodity differentials specific to the Trust (notes 15 and 16):

| | 2007 | 2008 | 2009 | 2010 | 2011 |
|---|---|---|---|---|---|
| WTI crude oil *(US$/bbl)* | 65.73 | 68.82 | 62.42 | 58.37 | 55.20 |
| AECO natural gas *($/MMBtu)* | 7.72 | 8.59 | 7.74 | 7.55 | 7.72 |

The prices and costs subsequent to 2011 have been adjusted for estimated inflation at an estimated annual rate of 2.0 percent. Based on the ceiling test calculation, the Trust's estimated undiscounted future net cash flows associated with the proved reserves plus the cost less impairment of unproved properties exceeded the net book value of the petroleum and natural gas properties.

## 4. BANK LOAN AND CREDIT FACILITIES

The Company has a credit agreement with a syndicate of chartered banks. The credit facilities consist of an operating loan and a 364-day revolving loan. Advances or letters of credit (note 16) under the credit facilities can be drawn in either Canadian or U.S. funds and bear interest at the agent bank's prime lending rate, bankers' acceptance rates plus applicable margins or LIBOR rates plus applicable margins. The credit facilities aggregating $300 million are subject to semi-annual review and are secured by a floating charge over all of the Company's assets. At December 31, 2006 a total of $127.5 million were drawn under the credit facilities (December 31, 2005 – $123.6 million).

## 5. LONG-TERM DEBT

| *As at December 31* | 2006 | 2005 |
|---|---|---|
| 10.5% senior subordinated notes (US$247) | $ 288 | $ 288 |
| 9.625% senior subordinated notes (US$179,699) | 209,403 | 209,511 |
| | $ 209,691 | $ 209,799 |

### Senior Subordinated Notes

The company has US$247,000 senior subordinated notes bearing interest at 10.5 percent payable semi-annually with principal repayable on February 15, 2011. These notes are unsecured and are subordinate to the Company's bank credit facilities.

US$179.7 million of 9.625 percent senior subordinated notes due July 15, 2010 are unsecured and are subordinate to the Company's bank credit facilities. After July 15 of each of the following years, these notes are redeemable at the Company's option in whole or in part with not less than 30 nor more than 60 days' notice at the following redemption prices (expressed as a percentage of the principal amount of the notes): 2007 at 104.813%, 2008 at 102.406%, 2009 and thereafter at 100%. The Company entered into an interest rate swap contract converting the fixed rate to a floating rate reset quarterly at the three-month LIBOR rate plus 5.2 percent until the maturity of these notes (note 15).

Interest Expense

The Company incurred interest expense on its outstanding debt as follows:

| | 2006 | 2005 |
|---|---|---|
| Bank loan and other | $ 9,263 | $ 8,318 |
| Amortization of deferred charges | 1,267 | 1,492 |
| Long-term debt and convertible debentures | 24,430 | 23,314 |
| Total interest | $ 34,960 | $ 33,124 |

## 6. CONVERTIBLE UNSECURED SUBORDINATED DEBENTURES

On June 6, 2005 the Trust issued $100 million principal amount of 6.5 percent convertible unsecured subordinated debentures for net proceeds of $95.8 million. The debentures pay interest semi-annually and are convertible at the option of the holder at any time into fully paid trust units at a conversion price of $14.75 per trust unit. The debentures mature on December 31, 2010 at which time they are due and payable.

The debentures have been classified as debt net of the fair value of the conversion feature which has been classified as unitholders' equity. This resulted in $95.2 million being classified as debt and $4.8 million being classified as equity. Issue costs are being amortized over the term of the debentures, and the debt portion will accrete up to the principal balance at maturity. The accretion, amortization of issue costs and the interest paid are expensed as interest expense in the consolidated statements of operations. If the debentures are converted to trust units, a portion of the value of the conversion feature under unitholders' equity will be reclassified to unitholders' capital along with the principal amounts converted.

| | *Number of Debentures* | *Convertible Debentures* | *Conversion Feature of Debentures* |
|---|---|---|---|
| Issued on June 6, 2005 | 100,000 | $ 95,200 | $ 4,800 |
| Conversion | (22,848) | (21,755) | (1,102) |
| Accretion | – | 321 | – |
| Balance, December 31, 2005 | 77,152 | 73,766 | 3,698 |
| Conversion | (57,533) | (55,049) | (2,758) |
| Accretion | – | 189 | – |
| Balance, December 31, 2006 | 19,619 | $ 18,906 | $ 940 |

## 7. ASSET RETIREMENT OBLIGATIONS

| *As at December 31* | 2006 | 2005 |
|---|---|---|
| Balance, beginning of the year | $ 33,010 | $ 73,297 |
| Liabilities incurred | 1,199 | 406 |
| Liabilities settled | (1,747) | (1,637) |
| Acquisition of liabilities | – | 3,410 |
| Disposition of liabilities | (122) | (2,117) |
| Accretion | 2,678 | 5,762 |
| Change in estimate *(1)* | 4,837 | (46,111) |
| Balance, end of the year | $ 39,855 | $ 33,010 |

*(1) The change in estimate is partially due to the fluctuations in forecasted market prices of petroleum and natural gas which effect the projected economic life of the wells and facilities. This results in changes in the timing of wells and facilities being abandoned and reclaimed thus changing the discounted present value of asset retirement obligations. Other factors affecting the liability amount are change in status of wells and change in the estimated costs of abandonment and reclamations.*

The Trust's asset retirement obligations are based on the Trust's net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and the facilities and the estimated time period during which these costs will be incurred in the future. These costs are expected to be incurred over the next 52 years with the majority of costs incurred between 2044 and 2058. The undiscounted amount of estimated cash flow required to settle the retirement obligations at December 31, 2006 is $236 million. Estimated cash flow has been discounted at a credit-adjusted risk free rate of 8.0 percent and an inflation rate of 5.0 percent for the year 2007, 4.0 percent for 2008, 3.0 percent for 2009 and 2.0 percent thereafter.

## 8. UNITHOLDERS' CAPITAL

### Trust Units

The Trust is authorized to issue an unlimited number of trust units.

| *Trust Units* | *Number of units* | | *Amount* |
|---|---|---|---|
| Balance, December 31, 2004 | 66,538 | $ | 515,663 |
| Issued on conversion of debentures | 1,549 | | 22,859 |
| Issued on conversion of exchangeable shares | 363 | | 5,373 |
| Issued on exercise of trust unit rights | 369 | | 2,916 |
| Transfer from contributed surplus on exercise of trust unit rights | – | | 1,301 |
| Issued pursuant to distribution reinvestment program | 464 | | 6,908 |
| Balance, December 31, 2005 | 69,283 | | 555,020 |
| Issued on conversion of debentures | 3,901 | | 54,799 |
| Issued on conversion of exchangeable shares | 34 | | 720 |
| Issued on exercise of trust unit rights | 1,250 | | 8,509 |
| Transfer from contributed surplus on exercise of trust unit rights | – | | 4,434 |
| Issued pursuant to distribution reinvestment program | 654 | | 13,674 |
| Balance, December 31, 2006 | 75,122 | $ | 637,156 |

On October 18, 2004, the Trust implemented a Distribution Reinvestment Plan ("DRIP"). Under the DRIP, Canadian unitholders are entitled to reinvest monthly cash distributions in additional trust units of the Trust. At the discretion of the Trust, these additional units will be issued from treasury at 95 percent of the "weighted average closing price", or acquired on the market at prevailing market rates. For the purposes of the units issued from treasury, the "weighted average closing price" is calculated as the weighted average trading price of trust units for the period commencing on the second business day after the distribution record date and ending on the second business day immediately prior to the distribution payment date, such period not to exceed 20 trading days.

Trust units are redeemable at the option of the holder. The redemption price is equal to the lesser of 90 percent of the "market price" of the trust units on the TSX for the ten trading days after the trust units have been surrendered for redemption and the closing market price on the date the trust units have been surrendered for redemption. Trust units can be redeemed for cash to a maximum of $250,000 per month. Redemptions in excess of the cash limit, if not waived by the Trust, shall be satisfied by distribution of subordinate, unsecured redemption notes bearing interest at 12% per annum, due and payable no later than September 1, 2033.

## 9. NON-CONTROLLING INTEREST

The Company is authorized to issue an unlimited number of exchangeable shares. The exchangeable shares can be converted (at the option of the holder) into trust units at any time up to September 2, 2013. Up to 1.9 million exchangeable shares may be redeemed annually by the Company for either cash or the issue of trust units. The number of trust units issued upon conversion is based upon the exchange ratio in effect at the conversion date. The exchange ratio is calculated monthly based on the cash distribution paid divided by the weighted average trust unit price for the five-day trading period ending on the record date. The exchange ratio at December 31, 2006 was 1.51072 trust units per exchangeable share (2005 – 1.37201 trust units per exchangeable share). Cash distributions are not paid on the exchangeable shares. The exchangeable shares are not publicly traded, although they may be transferred by the holder without first being converted to trust units.

The exchangeable shares of the Company are presented as a non-controlling interest on the consolidated balance sheet because they fail to meet the non-transferability criteria necessary in order for them to be classified as equity. Net income has been reduced by an amount equivalent to the non-controlling interest proportionate share of the Trust's consolidated net income with a corresponding increase to the non-controlling interest on the balance sheet.

| *Non-controlling Interest* | *Number of Exchangeable Shares* | | *Amount* |
|---|---|---|---|
| Balance, December 31, 2004 | 1,876 | $ | 12,936 |
| Exchanged for trust units | (279) | | (1,975) |
| Non-controlling interest in net income | – | | 1,849 |
| Balance, December 31, 2005 | 1,597 | | 12,810 |
| Exchanged for trust units | (24) | | (208) |
| Non-controlling interest in net income | – | | 4,585 |
| Balance, December 31, 2006 | 1,573 | $ | 17,187 |

As the exchangeable shares are converted to trust units, the exchange is accounted for as a step-acquisition whereby Unitholders' capital is increased by the fair value of the trust units issued. The difference between the fair value of the trust units issued and the book value of the exchangeable shares is recorded as an increase in petroleum and natural gas properties.

## 10. TRUST UNIT RIGHTS INCENTIVE PLAN

The Trust has a Trust Unit Rights Incentive Plan (the "Plan") whereby the maximum number of trust units issuable pursuant to the plan is a "rolling" maximum equal to 10 percent of the outstanding trust units plus the number of trust units which may be issued on the exchange of outstanding exchangeable shares. Any increase in the issued and outstanding units will result in an increase in the available number of trust units issuable under the plan, and any exercises of incentive rights will make new grants available under the plan, effectively resulting in a re-loading of the number of rights available to grant under the plan. Trust unit rights are granted at the volume weighted average trading price of the trust units for the five trading days prior to the date of grant, vest over three years and have a term of five years. The Plan provides for the exercise price of the rights to be reduced in future periods by a portion of the future distributions, subject to certain performance criteria.

The Trust recorded compensation expense of $7.5 million for the year ended December 31, 2006 ($5.3 million in 2005) related to the rights granted under the Plan.

Effective January 1, 2006, the Trust has commenced using the binomial-lattice model to calculate the estimated fair value of the unit rights issued. The following assumptions were used to arrive at the estimate of fair values:

| | **2006** | 2005 |
|---|---|---|
| Expected annual right's exercise price reduction | **$ 2.16** | $ 1.80 |
| Expected volatility | **23% – 28%** | 23% |
| Risk-free interest rate | **3.54% – 4.45%** | 3.30% – 3.84% |
| Expected life of right *(years)* | **Various** *(1)* | 5 |

*(1) The binomial-lattice model calculates the fair values based on an optimal strategy, resulting in various expected life of unit rights. The maximum term is limited to five years by the Trust Unit Rights Incentive Plan.*

The number of unit rights outstanding and exercise prices are detailed below:

| | *Number of Rights* | *Weighted Average Exercise Price (1)* |
|---|---|---|
| Balance, December 31, 2004 | 3,537 | $ 9.60 |
| Granted | 2,451 | $ 15.01 |
| Exercised | (369) | $ 7.90 |
| Cancelled | (253) | $ 9.83 |
| Balance, December 31, 2005 | 5,366 | $ 10.88 |
| Granted | 2,443 | $ 21.66 |
| Exercised | (1,250) | $ 6.81 |
| Cancelled | (246) | $ 11.54 |
| Balance, December 31, 2006 | 6,313 | $ 14.00 |

*(1) Exercise price reflects grant prices less reduction in exercise price as discussed above.*

The following table summarizes information about the unit rights outstanding at December 31, 2006:

| *Range of Exercise Prices* | *Number Outstanding at December 31, 2006* | *Weighted Average Remaining Term (years)* | *Weighted Average Exercise Price* | *Number Exercisable at December 31, 2006* | *Weighted Average Exercise Price* |
|---|---|---|---|---|---|
| $ 3.25 to $ 8.00 | 1,191 | 2.0 | $ 5.14 | 1,033 | $ 4.89 |
| $ 8.01 to $12.00 | 930 | 3.1 | $ 9.33 | 435 | $ 8.94 |
| $12.01 to $16.00 | 2,085 | 3.9 | $ 13.31 | 552 | $ 12.93 |
| $16.01 to $20.00 | 270 | 4.6 | $ 19.43 | – | – |
| $20.01 to $24.05 | 1,837 | 4.8 | $ 22.10 | – | – |
| $ 3.25 to $24.05 | 6,313 | 3.7 | $ 14.00 | 2,020 | $ 7.96 |

## 11. NET INCOME PER UNIT

The Trust applies the treasury stock method to assess the dilutive effect of outstanding trust unit rights on net income per unit. The weighted average exchangeable shares outstanding during the year, converted at the year-end exchange ratio, and the trust units issuable on conversion of convertible debentures, have also been included in the calculation of the diluted weighted average number of trust units outstanding:

| 2006 | *Net income* | *Trust units* | *Net income per trust unit* |
|---|---|---|---|
| Net income per basic unit | $ 147,069 | 72,947 | $ 2.02 |
| Dilutive effect of trust unit rights | – | 2,592 | |
| Conversion of convertible debentures | 1,647 | 2,515 | |
| Exchange of exchangeable shares | 4,585 | 2,384 | |
| Net income per diluted unit | $ 153,301 | 80,438 | $ 1.91 |

| 2005 | *Net income* | *Trust units* | *Net income per trust unit* |
|---|---|---|---|
| Net income per basic unit | $ 79,876 | 67,382 | $ 1.19 |
| Dilutive effect of trust unit rights | – | 1,438 | |
| Conversion of convertible debentures | 3,168 | 2,981 | |
| Exchange of exchangeable shares | 1,849 | 2,330 | |
| Net income per diluted unit | $ 84,893 | 74,131 | $ 1.15 |

The dilutive effect of trust unit incentive rights above did not include 2.1 million trust unit rights (2005 – 3.9 million) because the respective proceeds of exercise plus the amount of compensation expense attributed to future services and not yet recognized exceeded the average market price of the trust units during the year.

## 12. TAXES (RECOVERY)

The provision for (recovery of) taxes has been computed as follows:

| | 2006 | 2005 |
|---|---|---|
| Income before income taxes and non-controlling interest | $ 118,899 | $ 83,398 |
| *Expected income taxes (recovery) at the statutory rate of 37.0% (2005 – 40.10%)* | 43,992 | 33,443 |
| Increase (decrease) in taxes resulting from: | | |
| Resource allowance | (11,236) | (13,650) |
| Alberta royalty tax credit | (110) | (130) |
| Net income of the Trust | (56,261) | (29,415) |
| Non-taxable portion of foreign exchange gain | (20) | (1,360) |
| Effect of change in tax rate | (26,175) | 2,734 |
| Effect of change in opening tax pool balances | 3,451 | 851 |
| Effect of change in valuation allowance | 1,597 | (1,400) |
| Unit based compensation | 2,760 | 2,143 |
| Other | 833 | (290) |
| Current taxes | 8,414 | 8,747 |
| Provision for (recovery of) taxes | $ (32,755) | $ 1,673 |

The components of future income taxes are as follows:

| *As at December 31* | | 2006 | | 2005 |
|---|---|---|---|---|
| Future income tax liabilities: | | | | |
| Petroleum and natural gas properties | $ | 136,955 | $ | 170,008 |
| Other | | 10,019 | | 13,304 |
| Future income tax assets: | | | | |
| Asset retirement obligations | | (11,987) | | (11,917) |
| Reorganization costs | | – | | (7,212) |
| Loss carry-forward *(1)* | | (12,049) | | (4,438) |
| Other | | (4,080) | | – |
| Future income taxes | $ | 118,858 | $ | 159,745 |

*(1) $50 million of the loss carry-forward to expire in 2014, $18 million to expire in 2015.*

On October 31, 2006, the Federal Government announced its intention to tax the distributions of income trusts beginning in 2011 at the corporate tax rates. If this legislation is enacted, there could potentially be additional future income taxes to be recorded by the Trust. At this time, an estimate of the financial effect of the announcement has not been made.

## 13. CASH FLOW INFORMATION

Change in Non-Cash Working Capital Items

| | | 2006 | | 2005 |
|---|---|---|---|---|
| Current assets | $ | 9,525 | $ | (35,401) |
| Current liabilities | | (18,445) | | 16,410 |
| | $ | (8,920) | $ | (18,991) |
| Changes in non-cash working capital related to: | | | | |
| Operating activities | $ | (9,058) | $ | (20,212) |
| Investing activities | | 138 | | 1,221 |
| | $ | (8,920) | $ | (18,991) |

During the year the Trust made the following cash outlays in respect of interest expense and current income taxes.

| | | 2006 | | 2005 |
|---|---|---|---|---|
| Interest | $ | 32,373 | $ | 29,728 |
| Current income taxes | $ | 7,636 | $ | 8,536 |

## 14. FINANCIAL INSTRUMENTS AND CREDIT RISK

The Trust's financial instruments recognized in the balance sheet consist of cash and cash equivalents, accounts receivable, current liabilities, bank loan and long-term borrowings. The estimated fair values of the financial instruments have been determined based on the Trust's assessment of available market information and appropriate valuation methodologies; however, these estimates may not necessarily be indicative of the amounts that could be realized or settled in a market transaction.

The fair values of financial instruments other than bank loan and long-term borrowings approximate their book amounts due to the short-term maturity of these instruments. The fair value of the bank debt approximates its book value as it is at a market rate of interest. At December 31, 2006, the trading value of the Company's senior subordinated term notes was 106 percent in relation to par (2005 – 105 percent). The market value of the Trust's convertible debentures at December 31, 2006 was 146 percent in relation to par (2005 – 118 percent).

Most of the Trust's accounts receivable relate to oil and natural gas sales and are exposed to typical industry credit risks. The Trust manages this credit risk by entering into sales contracts with only credit worthy entities and reviewing its exposure to individual entities on a regular basis. The book value of the accounts receivable reflects management's assessment of the associated credit risks.

The Trust is exposed to interest rate risk as a result of its floating rate debts.

## 15. FINANCIAL DERIVATIVE CONTRACTS

The nature of the Trust's operations results in exposure to fluctuations in commodity prices, exchange rates and interest rates. The Trust monitors and, when appropriate, utilizes derivative contracts to manage its exposure to these risks. The Trust is exposed to credit-related losses in the event of non-performance by counter-parties to these contracts.

At December 31, 2006, the Trust had the following derivative contracts:

| *OIL* | *Period* | *Volume* | *Price* | *Index* |
|---|---|---|---|---|
| Price collar | Calendar 2007 | 2,000 bbl/d | US$55.00 – $83.60 | WTI |
| Price collar | Calendar 2007 | 3,000 bbl/d | US$55.00 – $83.75 | WTI |
| Price collar | Calendar 2007 | 2,000 bbl/d | US$60.00 – $80.40 | WTI |
| Price collar | Calendar 2007 | 1,000 bbl/d | US$60.00 – $80.60 | WTI |

| *FOREIGN CURRENCY* | *Period* | *Amount* | *Floor* | *Cap* |
|---|---|---|---|---|
| Collar | Calendar 2007 | US$5,000,000 per month | Cdn/US$1.0835 | Cdn/US$1.1600 |

| *INTEREST RATE* | *Period* | *Principal* | *Rate* |
|---|---|---|---|
| Swap | November 2003 to July 2010 | US$179,699,000 | 3-month LIBOR plus 5.2% |

Under the CICA guideline for hedge accounting, the Trust's financial derivative contracts for oil collars and foreign currency exchange do not qualify as effective accounting hedges. Accordingly, these contracts have been accounted for based on the fair value method. At December 31, 2006, the Trust recorded a current asset of $3.4 million and a current liability of $1.1 million (2005 – a current asset of $5.2 million) on the mark-to-market value of the outstanding non-hedging financial derivatives. The change in the mark-to-market value of the non-hedging financial derivatives during 2006 has been recorded as an unrealized loss on financial derivatives of $2.8 million (2005 – unrealized gain of $14.7 million) in the consolidated statement of operations. The Trust is applying hedge accounting to the interest rate swap and gains and losses are included in interest expense. At December 31, 2006, the mark-to-market value of the interest rate swap was a liability of $6.0 million (2005 – $5.4 million).

## 16. COMMITMENTS AND CONTINGENCIES

In October 2002, the Trust entered into a long-term crude oil supply contract with a third party that requires the delivery of up to 20,000 barrels per day of Lloydminster Blend crude oil at a price fixed at 71 percent of NYMEX WTI oil price. The contract is for an initial term of five years commencing January 1, 2003. The contract volumes increased from 9,000 barrels per day in January 2003 to 20,000 barrels per day in October 2003 and thereafter.

At December 31, 2006, the Trust had the following natural gas physical sales contracts:

| *GAS* | *Period* | *Volume* | *Price* |
|---|---|---|---|
| Price collar | November 1, 2006 to March 31, 2007 | 5,000 GJ/d | \$8.00 – \$9.45 |
| Price collar | November 1, 2006 to March 31, 2007 | 5,000 GJ/d | \$8.00 – \$9.50 |
| Price collar | November 1, 2006 to March 31, 2007 | 5,000 GJ/d | \$8.00 – \$10.15 |
| Price collar | April 1, 2007 to October 31, 2007 | 5,000 GJ/d | \$6.65 – \$9.15 |
| Price collar | April 1, 2007 to October 31, 2007 | 5,000 GJ/d | \$6.65 – \$9.30 |

Subsequent to December 31, 2006, the Trust added the following natural gas physical sales contracts:

| *GAS* | *Period* | *Volume* | *Price* |
|---|---|---|---|
| Price collar | April 1, 2007 to October 31, 2007 | 2,500 GJ/d | \$6.65 – \$8.25 |
| Price collar | April 1, 2007 to October 31, 2007 | 2,000 GJ/d | \$6.65 – \$8.30 |
| Price collar | April 1, 2007 to October 31, 2007 | 2,500 GJ/d | \$6.65 – \$8.73 |

At December 31, 2006, the Trust had operating lease and transportation obligations as detailed below:

| *(\$ thousands)* | | | *Payments Due* | | | |
|---|---|---|---|---|---|---|
| | *Total* | *1 year* | *2 years* | *3 years* | *4 years* | *5 years* |
| Operating leases | \$ 6,891 | \$ 1,761 | \$ 2,199 | \$ 2,199 | \$ 732 | \$ – |
| Transportation agreements | 3,177 | 2,015 | 926 | 204 | 26 | 6 |
| Total | \$ 10,068 | \$ 3,776 | \$ 3,125 | \$ 2,403 | \$ 758 | \$ 6 |

At December 31, 2006, there are outstanding letters of credit aggregating \$7.3 million (2005 – \$7.1 million) issued as security for performance under certain contracts.

The Company has future contractual processing obligations with respect to assets acquired. The fair value (\$7.8 million) of the original obligation is being drawn down over the life of the obligations which continue until October 2008.

In connection with a purchase of properties, Baytex became liable for contingent consideration whereby an additional amount would be payable by Baytex if the price for crude oil exceeds a base price in each of the succeeding six years. As at December 31, 2006, an additional \$0.5 million was paid for year one's obligations under the agreement and has been recorded as an adjustment to the original purchase price of the properties. It is currently not determinable if further payments will be required under this agreement, therefore no accrual has been made.

The Trust is engaged in litigation and claims arising in the normal course of operations, none of which could reasonably be expected to materially affect the Trust's financial position or reported results of operations.

## 17. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES

The Consolidated Financial Statements have been prepared in accordance with accounting principles generally accepted in Canada ("Canadian GAAP"). The significant differences between Canadian and United States GAAP, as applicable to these consolidated financial statements and notes, are described in the Trust's Form 40-F, which is filed with the United States Securities and Exchange Commission.

The following table summarizes certain information with regard to Baytex's oil and gas reserves as evaluated by Sproule Associates Limited as at December 31, 2006. Additional information required under NI 51-101 is included in the Annual Information Form for fiscal 2006.

*Summary of Oil and Gas Reserves (Forecast Prices and Costs)*

| *As at December 31, 2006* | *Light and Medium Oil* | | *Heavy Oil* | |
|---|---|---|---|---|
| | *Gross (1)* | *Net (2)* | *Gross (1)* | *Net* |
| | *(Mbbl)* | *(Mbbl)* | *(Mbbl)* | *(Mbbl)* |
| Proved | | | | |
| Developed producing | 3,223 | 2,932 | 22,000 | 18,983 |
| Developed non-producing | 470 | 389 | 23,723 | 20,597 |
| Undeveloped | 1,493 | 1,277 | 30,085 | 27,208 |
| Total proved | 5,186 | 4,598 | 75,808 | 66,788 |
| Probable | 2,044 | 1,828 | 32,929 | 28,664 |
| Total proved plus probable | 7,230 | 6,426 | 108,737 | 95,452 |

*Notes:*

*(1) "Gross" reserves are the working interest share of remaining reserves, before deduction of any royalties and excluding any royalty interest.*

*(2) "Net" reserves means Baytex's gross reserves less all royalties payable to others.*

*(3) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf : 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

*Reconciliation of Working Interest Reserves (1)*

*By Principal Product Type (Forecast Prices and Costs)*

| | *Light and Medium Oil* | | | *Heavy Oil* | | |
|---|---|---|---|---|---|---|
| *Factors* | *Proved* | *Probable* | *Proved + Probable* | *Proved* | *Probable* | *Proved + Probable* |
| | *(Mbbl)* | *(Mbbl)* | *(Mbbl)* | *(Mbbl)* | *(Mbbl)* | *(Mbbl)* |
| December 31 2005 | 5,472 | 2,342 | 7,814 | 71,266 | 26,286 | 97,552 |
| Extensions | – | – | – | 1,828 | 887 | 2,715 |
| Discoveries | 25 | 12 | 37 | 90 | 25 | 115 |
| Technical revisions | 312 | (351) | (39) | 9,890 | 5,649 | 15,539 |
| Acquisitions | 121 | 51 | 172 | – | – | – |
| Dispositions | – | – | – | – | – | – |
| Economic factors | 36 | (10) | 26 | 518 | 82 | 600 |
| Production | (780) | – | (780) | (7,784) | – | (7,784) |
| December 31, 2006 | 5,186 | 2,044 | 7,230 | 75,808 | 32,929 | 108,737 |

*Notes:*

*(1) Working interest reserves include solution gas but do not include royalty interest.*

*(2) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf : 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

| Natural Gas Liquids | | Natural Gas | | Oil Equivalent (2) | |
|---|---|---|---|---|---|
| Gross (1) | Net (2) | Gross (1) | Net (2) | Gross (1) | Net (2) |
| (Mbbl) | (Mbbl) | (Bcf) | (Bcf) | (Mboe) | (Mboe) |
| 2,240 | 1,903 | 79.0 | 66.3 | 40,624 | 34,861 |
| 592 | 506 | 12.0 | 10.0 | 26,785 | 23,180 |
| 630 | 482 | 17.4 | 12.9 | 35,119 | 31,110 |
| 3,462 | 2,891 | 108.4 | 89.2 | 102,528 | 89,151 |
| 1,014 | 835 | 39.7 | 33.1 | 42,592 | 36,840 |
| 4,476 | 3,726 | 148.1 | 122.3 | 145,120 | 125,991 |

| Natural Gas Liquids | | | Natural Gas | | | Oil Equivalent (2) | | |
|---|---|---|---|---|---|---|---|---|
| Proved | Probable | Proved + Probable | Proved | Probable | Proved + Probable | Proved | Probable | Proved + Probable |
| (Mbbl) | (Mbbl) | (Mbbl) | (MMcf) | (MMcf) | (MMcf) | (Mboe) | (Mboe) | (Mboe) |
| 3,635 | 1,254 | 4,889 | 125,537 | 50,862 | 176,399 | 101,296 | 38,359 | 139,655 |
| 138 | 29 | 167 | 4,817 | 90 | 4,907 | 2,769 | 931 | 3,700 |
| 76 | 26 | 102 | 2,458 | 1,449 | 3,907 | 601 | 305 | 906 |
| 308 | (226) | 82 | (2,425) | (11,535) | (13,960) | 10,106 | 3,150 | 13,256 |
| – | – | – | 32 | 15 | 47 | 127 | 53 | 180 |
| – | – | – | – | – | – | – | – | – |
| (112) | (69) | (181) | (1,779) | (1,244) | (3,023) | 146 | (206) | (60) |
| (583) | – | (583) | (20,219) | – | (20,219) | (12,517) | – | (12,517) |
| 3,462 | 1,014 | 4,476 | 108,421 | 39,637 | 148,058 | 102,528 | 42,592 | 145,120 |

*Reserve Life Index*

| | 2007 Production Target | Reserve Life Index (years) Total Proved | Proved Plus Probable |
|---|---|---|---|
| Oil and NGL *(bbl/d)* | 25,225 | 9.2 | 13.1 |
| Natural gas *(MMcf/d)* | 55.0 | 5.4 | 7.4 |
| Oil equivalent *(boe/d)* | 34,400 | 8.2 | 11.6 |

*Net Present Value of Reserves (Forecast Prices and Costs)*

| | Summary of Net Present Value of Future Net Revenue As at December 31, 2006 Forecast Prices and Costs Before Income Taxes Discounted at (percent/year) | | |
|---|---|---|---|
| *Reserves Category ($ millions)* | *0%* | *5%* | *10%* |
| Proved | | | |
| Developed producing | 857 | 833 | 757 |
| Developed non-producing | 482 | 347 | 265 |
| Undeveloped | 404 | 287 | 208 |
| Total proved | 1,743 | 1,467 | 1,230 |
| Probable | 835 | 555 | 401 |
| Total proved plus probable | 2,578 | 2,022 | 1,631 |

*Sproule December 31, 2006 Price Forecast*

| *Year* | *WTI Cushing US$/bbl* | *Edmonton Par Price Cdn$/bbl* | *Hardisty Heavy 12 API Cdn$/bbl* | *AECO-C Spot Cdn$/MMBtu* | *Inflation Rate %/Year* | *Exchange Rate Cdn$/US$* |
|---|---|---|---|---|---|---|
| 2007 | 65.73 | 74.10 | 42.98 | 7.72 | 5.0 | 0.87 |
| 2008 | 68.87 | 77.62 | 45.02 | 8.59 | 4.0 | 0.87 |
| 2009 | 62.42 | 70.25 | 40.74 | 7.74 | 3.0 | 0.87 |
| 2010 | 58.37 | 65.56 | 38.03 | 7.55 | 2.0 | 0.87 |
| 2011 | 55.20 | 61.90 | 35.90 | 7.72 | 2.0 | 0.87 |
| 2012 | 56.31 | 63.15 | 36.63 | 7.80 | 2.0 | 0.87 |
| 2013 | 57.43 | 64.42 | 37.36 | 7.99 | 2.0 | 0.87 |
| 2014 | 58.58 | 65.72 | 38.12 | 8.12 | 2.0 | 0.87 |

*Thereafter prices are escalated at 1.5% per year.*

*Finding, Development and Acquisition Costs*

| | **2006** | 2005 | 2004 | *3-Year Total* |
|---|---|---|---|---|
| Capital expenditures *($ millions)* | **133.1** | 152.4 | 280.7 | 566.2 |
| Heavy oil/light oil and natural gas spending | **54%/46%** | 58%/42% | 25%/75% | 40%/60% |

| | *Proved* | | | *Proved Plus Probable* | | |
|---|---|---|---|---|---|---|
| *($/boe)* | **2006** | 2005 | *3-Year Weighted Average* | **2006** | 2005 | *3-Year Weighted Average* |
| Excluding future development costs: | | | | | | |
| Finding and development costs | **9.61** | 8.94 | 9.96 | **7.35** | 8.16 | 8.14 |
| Acquisition costs (net of dispositions) | **5.38** | 1.48 | 7.49 | **3.89** | 1.33 | 6.32 |
| Finding, development and acquisition costs | **9.57** | 5.19 | 8.89 | **7.31** | 4.69 | 7.36 |
| Including future development costs: | | | | | | |
| Finding and development costs | **20.49** | 13.50 | 16.49 | **15.77** | 12.38 | 13.73 |
| Acquisition costs (net of dispositions) | **6.46** | 3.46 | 9.25 | **4.44** | 3.13 | 7.84 |
| Finding, development and acquisition costs | **20.36** | 8.45 | 13.33 | **15.66** | 7.69 | 11.20 |

*Notes:*

*(1) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.*

*(2) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly is used in isolation. A BOE conversion ratio of 6 Mcf : 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at eh wellhead.*

*Net Asset Value*

The following net asset value calculation utilizes what is generally referred to as the "produce-out" net present value of Baytex's oil and gas reserves as evaluated by independent evaluators. It does not take into account the possibility of Baytex being able to recognize additional reserves beyond those included in the 2006 year-end report.

| | *Discounted at* | |
|---|---|---|
| *($ millions, except unit and per unit data)* | *5%* | *10%* |
| Net present value of proved plus probable reserves *(1)* | 2,021.7 | 1,631.3 |
| Value of undeveloped land *(2)* | 100.1 | 100.1 |
| Net debt *(3)* | (347.9) | (347.9) |
| Net asset value | 1,773.9 | 1,383.5 |
| Total trust units outstanding *(4)* *(millions)* | 78.8 | 78.8 |
| Net asset value per trust unit *($)* | 22.50 | 17.55 |

*Notes:*

*(1) As evaluated by Sproule Associates Limited as at December 31, 2006. Net Present Value of future net revenue does not represent fair value of reserves.*

*(2) As evaluated by Baytex as at December 31, 2006 on 618,135 net acres of undeveloped land.*

*(3) Long-term debt net of working capital as at December 31, 2006, excluding convertible debentures and notional assets associated with the mark-to-market value of derivative contracts.*

*(4) Includes 75,121,664 trust units, 1,573,153 exchangeable shares converted at an average exchange ratio of 1.51072 and 1,330,102 trust units issuable on the conversion of outstanding convertible debentures as at December 31, 2006.*

## FINANCIAL

| *($ thousands, except per share amounts)* | 2006 | 2005 | 2004 [3] | 2003 [3] | 2002 |
|---|---|---|---|---|---|
| Petroleum and natural gas sales | **556,689** | 546,940 | 420,400 | 403,022 | 372,037 |
| Cash flow from operations [1] | **274,662** | 227,465 | 136,012 | 138,233 | 191,086 |
| Per unit/share – basic | **3.77** | 3.38 | 2.17 | 2.56 | 3.65 |
| Cash distributions | **143,072** | 114,221 | 113,063 | 33,382 | – |
| Per unit | **2.16** | 1.80 | 1.80 | 0.60 | – |
| Net income | **147,069** | 79,876 | 16,764 | 34,141 | 41,706 |
| Per unit/share – basic | **2.02** | 1.19 | 0.27 | 0.63 | 0.80 |
| Capital expenditures | **133,083** | 152,449 | 280,666 | 48,383 | 126,468 |
| Total debt | **364,417** | 418,476 | 422,044 | 213,572 | 362,775 |
| Total assets | **1,079,629** | 1,105,567 | 1,104,136 | 982,640 | 997,760 |

## OPERATIONS

| | 2006 | 2005 | 2004 | 2003 | 2002 |
|---|---|---|---|---|---|
| Production | | | | | |
| Light oil and NGL *(bbl/d)* | **3,735** | 3,842 | 2,172 | 2,273 | 3,154 |
| Heavy oil *(bbl/d)* | **21,325** | 21,265 | 22,703 | 23,911 | 23,967 |
| Total oil and NGL *(bbl/d)* | **25,060** | 25,107 | 24,875 | 26,184 | 27,121 |
| Natural gas *(MMcf/d)* | **55.4** | 60.4 | 54.9 | 63.0 | 72.6 |
| Oil equivalent *(boe/d)* | **34,292** | 35,177 | 34,022 | 36,686 | 39,214 |
| Reserves [2] | | | | | |
| Crude oil and NGL *(Mbbl)* | | | | | |
| Proved | **84,456** | 80,373 | 65,933 | 62,987 | 104,584 |
| Probable | **35,987** | 29,882 | 27,908 | 25,350 | 25,637 |
| Total | **120,443** | 110,255 | 93,841 | 88,337 | 130,221 |
| Natural gas *(Bcf)* | | | | | |
| Proved | **108.4** | 125.5 | 111.0 | 81.2 | 75.6 |
| Probable | **39.7** | 50.9 | 44.1 | 24.6 | 13.5 |
| Total | **148.1** | 176.4 | 155.1 | 105.8 | 89.1 |
| Wells drilled (gross) | | | | | |
| Oil | **98** | 64 | 104 | 173 | 106 |
| Gas | **21** | 41 | 16 | 67 | 51 |
| Other | **3** | 4 | 7 | 7 | 3 |
| Dry | **6** | 9 | 11 | 19 | 26 |
| Total | **128** | 118 | 138 | 266 | 186 |

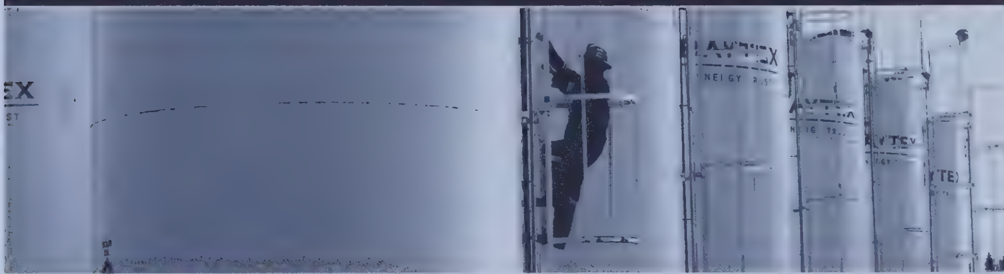
*(1) Cash flow from operations is a non-GAAP term that represents cash generated from operating activities before changes in non-cash working capital and other operating items. The Trust's cash flow from operations may not be comparable to other companies. The Trust considers cash flow a key measure of performance as it demonstrates the Trust's ability to generate the cash flow necessary to fund future distributions and capital investments.*

*(2) Reserves information from 2002 is prepared in accordance with National Policy 2-B. Probable reserves presented herein for those years represents 50 percent of the total probable reserves then assigned to allow more appropriate comparison with probable reserves under NI 51-101 as at December 31, 2003.*

*(3) Restated due to retroactive adoption of the fair value method of estimating compensation expense.*

# CORPORATE GOVERNANCE

*The Board of Directors and Management of Baytex are committed to ensuring proper corporate governance practices that meet current regulatory requirements.*





Baytex complies and will continue to comply with all applicable regulations with a goal of providing transparency and accountability in our corporate governance practices.

## MANDATE OF THE BOARD

The board of directors of Baytex is responsible for the stewardship of Baytex and the Trust and their subsidiaries. The board's mandate includes:

- the review and approval of the strategic direction of the Trust, its capital and financial plans, as well as implementation and monitoring of appropriate risk management systems;
- monitoring the progress, policies and procedures of the Trust, while providing guidance and advice to management and providing approval for any significant changes in the organizational structure;
- ensuring that the financial controls of the Trust are appropriate and comply with required standards, including accurate, complete and timely disclosure of information to unitholders, other security holders and regulators; and
- annual reviews of the composition and compensation of the board, and monitor its effectiveness, continuity and independence while ensuring the mandate of the board is continuously met.

The board of directors holds regularly scheduled meetings to review the business affairs of Baytex. The Chairman of the board is an independent director and has a separate role from that of the President and Chief Executive Officer.

## BOARD COMPOSITION

The board of directors of Baytex is currently composed of seven members, all of whom are independent and not members of management except for Mr. Raymond Chan, President and Chief Executive Officer.

## COMMITTEES

Individual directors are appointed by the board to sit on certain designated committees including the Audit Committee, Reserves Committee, Compensation Committee and Governance Committee. Each committee has a written board approved mandate outlining its purpose, membership, responsibility and accountability.

*Audit Committee*

The Audit Committee has responsibility for overseeing:

- the nature and scope of the annual audit;
- management's reporting on internal accounting standards and practices;
- financial information and accounting systems and procedures;
- financial reporting and statements; and
- recommending for board approval the interim and audited annual financial statements and other mandatory disclosure containing financial information.

The Audit Committee is comprised of three directors, none of whom is a member of the management of Baytex and all of whom are independent and financially literate. The Audit Committee meets at least quarterly and may meet more frequently as required.

*Reserves Committee*

The Reserves Committee has responsibility for:

- reviewing disclosure requirements and procedures with respect to the oil and gas activities of the Trust including those set forth under applicable securities legislations including National Instrument 51-101;
- reviewing procedures for providing information to the independent reserves evaluator;
- reviewing the appointment of the independent evaluator;
- recommending to the board of directors the approval of the annual independent reserves report and related information; and
- reviewing generally all matters relating to the preparation and public disclosure of reserves estimates.

The Reserves Committee is comprised of three directors, none of whom are members of the management of Baytex and all of whom are independent. Each member of the Reserves Committee has sufficient technical knowledge of oil and natural gas reserves to perform their duties under this committee. The Reserves Committee meets at least annually and may meet more frequently as required.

*Compensation Committee*

The Compensation Committee has the responsibility to review matters relating to the human resource policies and compensation of all directors, officers and employees of Baytex in the context of the approved budget and business plan. The Compensation Committee formulates and makes recommendations to the board regarding compensation and human resource issues.

The Compensation Committee is comprised of three directors, all of whom are independent. The Compensation Committee meets at least annually and may meet more frequently as required.

*Governance Committee*

The Governance Committee has the responsibility to review matters relating to corporate governance. The Governance Committee formulates and makes recommendations to the board regarding corporate governance issues.

The Governance Committee is comprised of three directors, all of whom are independent. The Governance Committee meets at least annually and may meet more frequently as required.

## CORPORATE GOVERNANCE POLICIES

*Policy on Business Conduct and Ethics*

Baytex's Policy on Business Conduct and Ethics is a statement of the principles to which Baytex is committed and is designed to direct all employees, officers and directors in the practice of ethical business conduct. The policy is a guide to the standards of behavior that we require in all of our business activities. Directors, officers and employees must know these standards and agree annually in writing to comply with the policy. The policy not only applies to Baytex employees, officers and directors, but also to independent contractors to the extent that they conduct activities on behalf of Baytex.

*Disclosure Policy*

The Disclosure Policy establishes procedures to permit the appropriate disclosure of information to the public in an informative, timely and broadly disseminated manner.

*Trading Policy*

The Trading Policy ensures that non-public information remains confidential and that trading of Baytex securities by directors, officers and employees is conducted in compliance with applicable securities laws.

*Whistle Blower Policy*

Baytex is committed to maintaining the highest standards of honesty and accountability in its business activities. Our employees, officers and directors are likely to be the first to know when someone inside the Company or connected with the Company is acting improperly or illegally. Baytex maintains procedures for the reporting of ethical violations which encourages all Baytex employees to report any misconduct. The procedure ensures that Baytex employees may report misconduct without the threat or fear of dismissal, harassment or other retaliation.

*Code of Ethics for Principal Executive Officer and Senior Financial Officers*

While Baytex and its unitholders expect honest and ethical conduct in all aspects of our business from all employees, officers and directors, Baytex and its unitholders expect the highest possible standard from our financial managers. This code of ethics is applicable to the President and Chief Executive Officer, Chief Financial Officer, Controller and any other person performing a similar function. These individuals are setting an example for other employees and are expected to foster a culture of transparency, integrity and honesty. Compliance with this code is an essential condition of employment for the financial officers and any violations will be met with immediate sanction.

A complete copy of the Baytex corporate governance policies can be found on the Baytex website at www.baytex.ab.ca or by contacting the Investor Relations Department of Baytex.

# SAFETY, ENVIRONMENT AND COMMUNITY

Baytex Energy Trust is committed to conducting its business safely and responsibly. Our philosophy is that safety and regulatory compliance are our highest priorities. We believe that long-term profitability can best be assured and enhanced thorough safe and compliant business practices. Baytex has a formal policy to conduct all operations in a manner which protects the health and safety of our workers, the public, and the environment.

In order to achieve this commitment, Baytex:

- Has developed a Health, Safety and Environment Policy and Management Plan which complies with all regulatory requirements and industry standards.
- Provides the necessary education and training to all employees and contract personnel to ensure that they understand their responsibilities within the Baytex Health, Safety and Environmental Policy.
- Maintains a contractor management program which ensures that all contractors and subcontractors understand and comply with Baytex policies.
- Conducts regular reviews of the safety and environmental program and regulatory requirements and updates the program as required. Input from employees is encouraged and is fully considered when conducting reviews.
- Conducts regular inspections and audits of Baytex-operated worksites to ensure they are in compliance with company policies and government regulations.
- Has developed, implemented and tested a Corporate Emergency Response Plan to ensure that company and contract personnel are prepared to respond to an emergency situation in an efficient and responsible manner.

This Health, Safety and Environment Policy is supported at every level in Baytex. Management is responsible for promoting these policies and ensuring that all necessary resources, equipment and training are provided. All employees and contractors are required to comply with the Health, Safety and Environment Policy. In addition, quarterly corporate safety and environment reports are submitted to and reviewed by the board of directors.

Baytex participates in the Environment, Health and Safety Stewardship Program conducted by the Canadian Association of Petroleum Producers (CAPP). The program was developed to set consistent safety and environmental standards throughout the Canadian oil and gas industry. It allows participants to measure the performance of their health, safety and environmental programs against other companies. Baytex is proud to report that it has achieved a "Gold" ranking under CAPP's program for five consecutive years.

Our commitment to the communities in which we operate goes well beyond our Health, Safety and Environment Policy. Baytex operates within the traditional areas of six aboriginal First Nations groups in western Canada. Baytex has undertaken consultation regarding resource development and has engaged in economic development with each of these native groups by providing contracting opportunities in our daily operations.

In addition, Baytex made a number of contributions to First Nations cultural, public safety and economic development programs during 2006. Baytex participates in "Energy in Action", a CAPP-sponsored program of youth education and environmental projects for small communities in oil and gas producing areas in western Canada. Baytex has also provided financial support for specific public safety and education projects in our operating areas. Examples include funding for a new volunteer fire hall for Britannia and Wilton, Saskatchewan and for the founding of the Oil and Gas Centre of Excellence at Northern Lights College in Fort St. John, British Columbia.

Baytex and its employees also make monetary and time contributions for a large number of charities in Calgary and other communities in our operating areas. During 2006, we provided significant contributions to organizations as diverse as the United Way of Calgary, the Alberta Children's Hospital, the Canadian Breast Cancer Foundation and Ducks Unlimited, among others.

Similarly, in the environmental area, Baytex has gone well beyond mandated reductions in emissions. Baytex has voluntarily undertaken an enhanced oil recovery project in our Stoddart field in northeastern British Columbia to inject carbon dioxide ($CO_2$) and hydrogen sulfide ($H_2S$) into a subsurface oil reservoir to remove these gases from the environment and to increase oil recovery. To date, approximately 36,000 metric tons of $CO_2$ and 119,000 metric tons of $H_2S$ have been permanently sequestered, while recovery of natural gas and oil has been simultaneously increased. In addition, Baytex has aggressively invested in numerous other projects in Alberta and Saskatchewan to tie-in natural gas volumes for sales that would otherwise be flared as a by-product of heavy oil production. These are concrete translations into action of our strong belief that long-term profitability is enhanced by proactive environmental stewardship.



*An enhanced oil recovery project in our Stoddart field injects carbon dioxide and hydrogen sulfide into a subsurface oil reservoir to remove these gases from the environment and to increase oil recovery.*

### BOARD OF DIRECTORS

*Edward Chwyl* (2)(3)(4)
Chairman of the Board
Independent Businessman

*John A. Brussa* (2)(3)(4)
Partner
Burnet, Duckworth & Palmer LLP

*W. A. Blake Cassidy* (1)(5)
Retired Banker

*Raymond T. Chan*
President and CEO
Baytex Energy Trust

*Naveen Dargan* (1)(2)(4)
Independent Businessman

*R. E. T. (Rusty) Goepel* (1)
Senior Vice President
Raymond James Ltd.

*Dale O. Shwed* (3)
President and CEO
Crew Energy Inc.

*(1) Member of the Audit Committee*
*(2) Member of the Compensation Committee*
*(3) Member of the Reserves Committee*
*(4) Member of the Governance Committee*
*(5) Will not stand for re-election*

### OFFICERS

*Raymond T. Chan*
President and
Chief Executive Officer

*W. Derek Aylesworth*
Chief Financial Officer

*Randal J. Best*
Senior Vice President,
Corporate Development

*Stephen Brownridge*
Vice President, Heavy Oil

*Anthony W. Marino*
Chief Operating Officer

*Brett J. McDonald*
Vice President, Land

*R. Shaun Paterson*
Vice President, Marketing

*Mark F. Smith*
Vice President,
Conventional Oil & Gas

### HEAD OFFICE

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Fax: 403-205-3845
Website: www.baytex.ab.ca
Toll-free: 1-800-524-5521

### AUDITORS

Deloitte & Touche LLP

### BANKERS

The Toronto-Dominion Bank
Bank of Nova Scotia
BNP Paribas (Canada)
National Bank of Canada
Royal Bank of Canada
Société Générale
Union Bank of Canada

### LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

### RESERVES ENGINEERS

Sproule Associates Limited

### TRANSFER AGENT

Valiant Trust Company

### EXCHANGE LISTING

Toronto Stock Exchange
Symbol: BTE.UN

New York Stock Exchange
Symbol: BTE

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*The Design Centre of Canada.*
*Printed in Canada.*

# ADVISORY AND ABBREVIATIONS

## ADVISORY

Certain statements in this report are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995. Specifically, this report contains forward-looking statements relating to Management's approach to operations, expectations relating to the number of wells, amount and timing of capital projects, foreign exchange rates, interest rates, worldwide and industry production, prices of oil and gas, heavy oil differentials, company production, cash flow, debt levels and cash distribution practices. The reader is cautioned that assumptions used in the preparation of such information, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; industry capacity; competitive action by other companies, fluctuations in oil and gas prices; the ability to produce and transport crude oil and natural gas to markets; the result of exploration and development drilling and related activities; fluctuation in foreign currency exchange rates; the imprecision of reserves estimates; the ability of suppliers to meet commitments; actions by governmental authorities including increases in taxes; decisions or approvals of administrative tribunals; change in environmental and other regulations; risks associated with oil and gas operations; the weather in the Trust's areas of operations; and other factors, many of which are beyond the control of the Trust. There is no representation by Baytex that actual results achieved during the forecast period will be the same in whole or in part as those forecast.

## ABBREVIATIONS

| | |
|---|---|
| *API* | American Petroleum Institute |
| *bbl* | barrel |
| *bbl/d* | barrel per day |
| *Bcf* | billion cubic feet |
| *boe** | barrels of oil equivalent |
| *boe/d** | barrels of oil equivalent per day |
| *Capex* | capital expenditures |
| *FD&A* | finding, development and acquisition costs |
| *F&D* | finding and development costs |
| *GAAP* | generally accepted accounting principles |
| *G&A* | general and administrative |
| *GJ* | gigajoule |
| *LLB* | Lloyd Light Blend |
| *Mbbl* | thousand barrels |
| *Mboe** | thousand barrels of oil equivalent |
| *Mcf* | thousand cubic feet |
| *Mcf/d* | thousand cubic feet per day |
| *MMbbl* | million barrels |
| *MMboe** | million barrels of oil equivalent |
| *MMBtu* | million British Thermal Units |
| *MMcf* | million cubic feet |
| *MMcf/d* | million cubic feet per day |
| *NAV* | net asset value |
| *NGL* | natural gas liquids |
| *NYMEX* | New York Mercantile Exchange |
| *RLI* | reserve life index |
| *WTI* | West Texas Intermediate |

** BOEs may be misleading, particularly if used in isolation. In accordance with NI 51-101, a BOE conversion ratio for natural gas of 6 Mcf : 1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

BAYTEX

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